Ontario Energy Board | Commission de l'énergie de l'Ontario

Market Surveillance Panel Monitoring Report 32

MONITORING REPORT ON THE IESO-ADMINISTERED ELECTRICITY MARKETS

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Role of the Market Surveillance Panel

The Market Surveillance Panel (Panel) is a panel of the Ontario Energy Board (OEB). Its role is to monitor, investigate and report on activities related to – and behaviour in – the wholesale electricity markets administered by the Independent Electricity System Operator (IESO).

The Panel monitors, evaluates and analyzes activities related to the IESO-Administered Markets and the conduct of Market Participants to identify:

1. inappropriate or anomalous conduct in the markets, including gaming and the abuse of market power;
2. activities of the IESO that may have an impact on market efficiencies or effective competition;
3. actual or potential design or other flaws and inefficiencies in the Market Rules and procedures; and
4. actual or potential design or other flaws in the overall structure of the IESO-Administered Markets and assess consistency of that structure with the efficient and fair operation of a competitive market.

Market-related activities and market conduct may also be the subject of a more formal and targeted investigation by the Panel. To that end, the Panel has authority under the *Electricity Act, 1998* to compel testimony and the production of information.

The Panel reports on the results of its monitoring and investigations. The Panel does not have the legislative mandate to impose sanctions or other remedies in response to inappropriate conduct or market defects, but it does make recommendations for remedial action as it considers appropriate.

Executive Summary

This is the 32nd Market Surveillance Panel Monitoring Report published since market opening in 2002. The report highlights current issues with the market that the Panel feels should be addressed (Chapter 3). The report also covers recent electricity sector events (Chapter 1), as well as historical events for the monitoring period November 1, 2017 to April 30, 2018 (referred to as the Winter 2017/18 Period in Chapter 2 and Appendix A).

This Monitoring Report is broken down into three chapters and an appendix:

- Chapter 1: General Assessment, Market Developments and Status of Recent Panel Recommendations
- Chapter 2: Analysis of Anomalous Market Outcomes for the Winter 2017/18 Period
- Chapter 3: Matters to Report in the Ontario Electricity Marketplace
- Appendix A: Market Outcomes for the Winter 2017/18 Period

Chapter 1: General Assessment, Market Developments and Status of Recent Panel Recommendations

Once annually, the Panel is required to provide a general assessment of the IESO-Administered Markets.[1] Given the number of significant changes currently being undertaken by the IESO through its Market Renewal Program (MRP), the Panel provides a more detailed analysis than it has undertaken in recent years regarding the competitiveness and efficiency of the IESO-Administered Markets. As part of this analysis, the Panel provides an overview of several well-known deficiencies in the current market – some of which are expected to be addressed as part of the MRP.

[1] See the OEB By-law #3, Article 7: “Once annually, such report shall contain the Panel’s general assessment of the state of the IESO-administered markets, including their efficiency and competitiveness.”, available at: https://www.oeb.ca/oeb/_Documents/About%20the%20OEB/OEB_bylaw_3.pdf

Overall, the Panel concludes that much of the long-term investment over the last decade has not been very competitive, imposed unnecessarily high costs on Ontario consumers and removed the transparency of price signals that lead to economic-based decision making. The Demand Response (DR) Auction also continues to annually procure capacity that is not required to maintain reliability. To date, the IESO has not activated any DR resources in the real-time energy market, although consumers have paid more than $200 million for this capacity.[2]

In terms of the spot energy market, the Panel concludes that it remains reasonably competitive. Nonetheless, the Panel urges the IESO to strive in all future procurement – either through its Capacity Auction (CA) or bilateral contracting – to ensure that the contract language is such that efficient marginal-cost bidding is maintained.

The Panel analyzed Ontario Power Generation's (OPG) acquisition of TransCanada (TC) Energy's assets, among others. No other competitive electricity market has as large a concentration of assets under the control of one (publicly owned, nonetheless) Market Participant. While out-of-market mechanisms, such as rate regulation and contract provisions, may mitigate the ability of OPG to exert market power, they may not eliminate it altogether. By increasing its control of installed capacity – both baseload and peaking assets – the potential risk of the exercise of market power, in the Panel's view, becomes more of a concern. The Panel notes the licence conditions that have been imposed by the Ontario Energy Board to address concerns about market power and the competitiveness of the IESO-Administered Markets, and expects to monitor performance under those licence conditions.

Finally, the Panel reiterates that the current design of the Industrial Conservation Initiative (ICI) program – in combination with a low-price environment and high Global Adjustment (GA) charges – creates an uneconomic and inefficient incentive to reduce demand when there is ample supply and capacity. The Panel remains of the view that only the cost of peak

[2] As of January 2020.

generation should be recovered through peak demand charges, while non-peak costs should be allocated such that all consumers who benefit from that capacity pay for it.

Chapter 2: Analysis of Anomalous Market Outcomes for the Winter 2017/18 Period

For the Winter 2017/18 Period, the long-term trend of low wholesale prices in Ontario continued, with 650 negative priced hours – a decrease from 1,065 negative-price hours in the Winter 2016/17 Period and the record 1,584 negative-price hours in the Summer 2017 Period. The average weighted Hourly Ontario Energy Price (HOEP) for Class B consumers in the Winter 2017/18 Period increased to $23.11/MWh from $20.14/MWh in the Winter 2016/17 Period. The average weighted HOEP for Class A ratepayers increased to $19.23/MWh from $17.17/MWh between the same periods.

The number of high-price hours – where HOEP is greater than $200/MWh – fell to 4 hours in the current monitoring period, compared to 20 hours in the same period last year. In nearly every case, the main contributing factor to high-price hours was a shortfall in variable generation. Failed import transactions and under-forecasted demand were secondary factors in most high-price hours.

This report examines a one-time error in the IESO's demand forecasting tool that resulted in a large discrepancy between pre-dispatch demand forecasts and real-time demand. This discrepancy only occurred in the unconstrained – or price-setting – sequence and resulted in a price spike in both the wholesale and Operating Reserve (OR) markets.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

OPG is the largest owner and operator of hydroelectric assets in the province's wholesale electricity market, with these generators playing a pivotal role in producing energy during hours when it is most valuable and often setting the Market Clearing Price (MCP). It is therefore essential to the efficiency of the wholesale market that OPG has a clear market incentive to use its hydroelectric assets efficiently.

A flat rate per MWh by itself provides no incentive to offer efficiently into Ontario’s wholesale electricity market and no incentive to maximize the value to consumers of those assets. As part of regulating the rates for many of OPG’s hydroelectric assets, the OEB approved a Hydroelectric Incentive Mechanism (HIM) whose purpose is to incent OPG to move production from periods of low value to periods of higher value, based on market signals. The effectiveness of the HIM as an incentive for OPG to shift energy at its hydroelectric assets in this way is weakened by structural changes in the market, and potentially by a revenue sharing mechanism that was introduced in 2011.

Over the last decade, OPG has reduced the amount of energy it shifts from low value to high value hours. The reduced time-shifting is seen most clearly in two places. The use of the Pump-Generating Station (PGS) at the Sir Adam Beck hydroelectric facility on the Niagara River, which is intended to store water when electricity market prices are low and to generate when market prices are high, has diminished in recent years: average hourly output at PGS declined by 80% between 2010 to 2018. Time-shifting of energy at OPG’s other regulated hydroelectric assets has also declined over the past decade.

There are a number of explanations for this decline, including flatter price curves, higher water levels and environmental and safety regulations. The Panel has not been able to assess the extent to which these factors have affected time-shifting, and is concerned that the sharing of HIM revenues has contributed to the decline.

The Panel believes that the design of the HIM should be robust to all plausible future market conditions. The Panel therefore suggests a re-examination of the revenue-sharing elements of the HIM to ensure that OPG has a clear market incentive to use its hydroelectric assets efficiently.

<u>Recommendation 3-1:</u>

The Panel recommends that the OEB consider revisiting the sharing with consumers of net HIM revenue exceeding a threshold. The Panel further recommends that the OEB

consider keeping the forecast used to determine the imputed HIM revenue in place for no less than three years, as has recently been the case.

Since May 2018, the IESO has relied on a new solution to address the need for greater system flexibility due to increased forecast uncertainty from variable generators. It accomplishes this by procuring an additional, predetermined amount – 200 MW – of OR, which is intended to schedule a generator that would otherwise not be committed to come online and provide greater capacity than their scheduled amount. This provides “spare energy” surplus to the forecast need for energy and OR. The solution is intended to reduce the amount of out-of-market actions undertaken by the IESO.

The Panel’s analysis of the solution highlights a number of shortcomings in terms of specificity, transparency and effectiveness. Notably, it lacks criteria for when it should be invoked, while relying largely on the discretion of the IESO to determine when “spare energy” is required. And because the solution relies on a predetermined amount of additional OR, it results in an “all or nothing” approach. It has also not reduced the primary out-of-market action taken by the IESO, the manual dispatch of the Lennox Generation Station.

While the current solution was intended to be temporary, it is now expected to remain in place beyond the MRP, which itself is several years from being completed.[3] The Panel recommends that the IESO re-consider its approach and develop a long-term, cost-effective solution.

<u>Recommendation 3-2:</u>

In order to provide more consistent market outcomes, the IESO should give further consideration to improving how the need for additional system flexibility is addressed, such as specifying the conditions that require intervention and scheduling the required amount of spinning reserve explicitly in the normal OR market. Although it is

[3] The IESO has informed the Panel that the existing solution is currently being reviewed and the IESO may look to further evolve the program.

acknowledged that no industry standard exists to address flexibility, alternative solutions should also be considered to ensure the most suitable approach is used.

Chapter 1: General Assessment, Market Developments and Status of Recent Panel Recommendations

1.1 General Assessment

Once a year, the Panel provides a general assessment of the IESO-Administered Markets, including its efficiency and competitiveness. In this Monitoring Report, the Panel provides a broader and more in-depth look at the current state of the IESO-Administered Markets than it has undertaken in recent years.

In recent annual assessments, the Panel has accepted many of the well-known and long-standing deficiencies of the market as inherent in the current market design. The Panel's assessment on the efficiency and competitiveness of the IESO-Administered Markets was done "within an Ontario context". On this limited basis, the Panel concluded that the market operated "in a reasonably satisfactory manner".[4]

Significant market design changes are being developed – including changes to the energy market as part of the MRP, and the proposed expansion of the DR Auction to include traditional generators and other resources. It seems appropriate now to take a more detailed look at concerns regarding the competitiveness and efficiency of the IESO-Administered Markets raised by the Panel over the years along with the developing design changes.

As the IESO and stakeholders move into the Detailed Design stage of Market Renewal, the Panel provides an overview of several deficiencies in the existing market and a commentary on the state of competition and efficiency in the market. While investment and operations interact directly, the Panel distinguishes between long-term investment decisions and short-term operating decisions as separate parts of the overall market. Ultimately, the Panel expects

[4] The last General Assessment was addressed in the Panel's Monitoring Report 29 (May 2016-Oct 2016) published March 2018, page 8, available at: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20180322.pdf

that this discussion will provide additional support for the necessary changes to the IESO-Administered Markets being proposed as part of the MRP.

1.1.1 The Market for Capacity in Ontario

The entry and exit of generating capacity has not occurred in the manner envisioned in the development of the competitive electricity market in Ontario. The Market Design Committee's original design of Ontario's competitive electricity market called for a real-time energy market complemented with bilateral contracting by Market Participants and, if necessary, a capacity market under shortage conditions.[5] The electricity market opened in May 2002, but the combination of a supply shortage, a hot summer and a drought brought high prices and consumer protests that led the government to cap retail prices in November 2002. This intervention and subsequent rate regulation shook investor confidence in merchant investment and subsequent generator investment has been almost entirely a result of long-term contracts. The result is today's "hybrid" market that includes long-term contractual procurement via government agencies, complemented by a real-time energy market.[6] This centrally-planned generation investment has been at times more or less competitive as different programs ranged from competitive bidding for a specified type and quantity of power – early Renewable Energy Supply (RES) contracts, for example – to specifying a price for a type of power and accepting all qualified bids, as in the Feed-in Tariff (FIT) program developed further to amendments to the *Electricity Act, 1998* made by the *Green Energy and Green Economy Act, 2009* (GEA). Generation procurement prior to 2009 was based on central plans for capacity needs, followed by competitive RFP processes for contracted generation of specific types (gas

[5] See the Market Design Committee Final report, dated January 29, 1999, Volume 1, pages 1-7 and 1-8: https://web.archive.org/web/20160125235649/http://www.ieso.ca/Documents/mdc/Reports/FinalReport/Volume-1.pdf

[6] The term "hybrid market" applies to most electricity markets today, as opposed to an "energy only" market, which has become increasingly rare.

plants and renewables) to meet those needs. The 2015 Auditor General's report criticized the replacement of competitive bidding for supply with Directives to secure new capacity at fixed high prices, procuring capacity that was not needed and for the suppression of technical analyses of generation needs.[7]

In a market-oriented electricity system – which can range from an "energy only" market to one with competitive capacity auctions or bilateral contracting – price signals lead buyers and sellers to efficient technology choices and timely and efficient capacity investment decisions. In contrast, much of the addition to Ontario's generation fleet since 2009 was procured through central planning and Ministerial Directives as to amount, technology and price, not price signals alone.[8] Some resources have been procured competitively through the DR Auction – but that level of capacity was determined through a Ministerial Directive, not actual supply needs (as is discussed at length below). Much of this out-of-market capacity is signed to long-term contracts, severely limiting economic decisions to shut down a plant if it is not needed.

Overall, the Panel concludes that while procurement prior to 2009 was reasonably competitive in response to public policy decisions, the procurement decisions regarding both the quantity and type of generation over the last decade have not been very competitive, imposing unnecessarily high costs on Ontario consumers.

The continued investment in new capacity despite a drop in demand has resulted in a near decade-long surplus of capacity which, combined with the procurement of contracted, near-zero marginal cost generators (wind and solar) has resulted in a near decade-long decline in wholesale energy prices. The fixed costs associated with contracted and price-regulated generators are paid for through the Global Adjustment (GA), added to the price of all energy

[7] See the Ontario Auditor General's 2015 Annual Report, Section 3.05 "Electricity Power System Planning": http://www.auditor.on.ca/en/content/annualreports/arreports/en15/3.05en15.pdf

[8] Even capacity auctions are centrally planned functions in some sense, since an intermediary – such as a system operator like the IESO – determines the appropriate level of capacity to be procured.

purchased by consumers (large and small). In 2008-2010 the GA represented between 10% and 49% of the total cost of electricity, while between 2016 and 2018 it represented between 76% and 85% of the total.

1.1.2 Market Renewal and Capacity Investment

The IESO's early plan for Market Renewal included an Incremental Capacity Auction (ICA). This was to be a competitive auction used to procure capacity when existing contracts expire and was intended to replace the use of institutional-led contracting. Capacity auctions allow a variety of resources – traditional generators, DR and imports, among others – to compete against one another in an auction to add capacity to the system. Most existing capacity auctions are run annually, and typically only commit resources for one year or a few years. They provide system operators with the flexibility to reduce or increase available capacity based on the forecasted needs of the grid – although they also come with their own suite of problems and criticisms. These include ensuring the appropriate operating characteristics to ensure that the system can be reliably operated, as well as the risk to consumers of under-supply if generators or their investors do not want to expose their investments in high capital cost, long lived assets to the risk of year by year procurements in the market. Initially, the Panel positively viewed the ICA as a replacement for long-term contracting, in part because it would shift some of the financial risk of capacity investment from ratepayers back to investors.[9]

The IESO stated that a capacity auction would be just one of the tools used to acquire new capacity, particularly if that capacity is a new resource, rather than a resource coming off contract or an investment at an existing generator to increase output (uprate). It appears that acceptance of "complementary mechanisms" refers to procurement through long-term

[9] See the Panel's submissions on the ICA from November 2018 and May 2019: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ica/ica-20181214-MSP.pdf?la=en and http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ica/2019/ica-20190517-market-surveillance-panel.pdf?la=en

contracts, in a tacit recognition that it seems unlikely that investment in large-scale greenfield generation facilities would occur without contracts for much of the useful life of the plant.[10] While the ICA could be an efficient means of procurement smaller investments, it would likely co-exist with long-term contracts for major projects.

The IESO recently concluded there is no need for new resources to meet “limited capacity needs over the next 10 years”.[11] As a result, the IESO has put the ICA on hold and replaced it with the Capacity Auction (CA) that will, at least initially, be an expansion of the current DR Auction to include a small number of non-contracted generators. The IESO’s explanation for putting the ICA on hold was that its updated “planning assumptions” showed a “limited need for new capacity”.[12] While the Panel would prefer to see a more expansive role for competition in the procurement of capacity, the CA is viewed as a potentially efficient means – if that capacity is required – of drawing new small players into the capacity market and of ensuring that the most cost-efficient of the contracted generators whose contracts come to an end in the near future succeed in the auction and continue to participate in the Ontario electricity market.

The IESO initially proposed commitment lengths of more than five years for the ICA and the Panel is concerned that these long commitments might carry over into the CA, although the IESO has not made a determination on this issue. Most neighbouring jurisdictions use one to three years for new capacity auctions.[13] Long commitment periods reduce the effectiveness of price signals and hinder the ability of an auction to respond to changing market conditions.

[10] See the IESO’s presentation “IESO Capacity Auction – June 2020 Auction”, dated November 27, 2019, slide 4: “The IESO will continue to explore the evolution of the Capacity Auction as well as determine what, if any, complementary mechanisms are needed to acquire capacity, aimed towards meeting all of our future resource adequacy needs”, available at: http://www.ieso.ca/-/media/Files/IESO/Document-Library/tp/2019/iesotp-201911275-june-2020-capacity-auction-presentation.pdf?la=en

[11] See the IESO email to stakeholders, “Market Renewal Update”, dated July, 16, 2019: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ica/2019/MRP-20190716-Communication.pdf?la=en

[12] Ibid.

[13] New England is the only North American jurisdiction with commitment periods longer than three years.

They may also leave ratepayers on the hook for surplus capacity. Some capacity auctions – including auctions from the New York Independent System Operator (NYISO) and the Midcontinent Independent System Operator (MISO) – have attracted enough resources to meet reliability needs without having to rely on five-year commitments. While generators will argue for long commitment periods, the Panel concludes that the IESO should keep those commitments short, since the goal is not large greenfield investment but retaining or enhancing existing facilities. When larger commitments are required, a competitive contracting process with contract terms and duration appropriate to the technically-estimated needs of the system should be established.

1.1.3 The DR Auction

The DR Auction is a means of encouraging loads to reduce their demand in response to price spikes, reduce the need for costly peaking generation resources, and to provide flexibility to the System Operator. While the DR Auction is competitive when viewed as a means of meeting a provincial Directive to secure capacity from DR resources, this part of the market is less competitive when analyzed more broadly, with two principal problems. First, the amount of capacity procured through the DR Auction has increased over time, despite the lack of demonstrated need for capacity. Second, the IESO has not done a thorough assessment of the cost and benefit – including reliability implications – of providing peak capacity through the DR Auction rather than through supply-side resources.

The concerns expressed by the Panel, both in previous semi-annual Monitoring Reports and in submissions to various stakeholder activities overseen by the IESO, are summarized in this section.[14]

[14] For a detailed examination of the IESO's DR Auction, see the Panel's Monitoring Report 28 (Nov 2015-April 2016) published May 2017: https://www.oeb.ca/sites/default/files/msp-report-nov2015-apr2016_20170508.pdf

The Need for DR Capacity Remains Unclear

Ontario remains in a position of surplus capacity, as detailed at length in recent IESO planning documents.[15] Nonetheless, the IESO has continued to procure DR capacity annually, despite the lack of need for such capacity. The most recent DR auction procured 859 MW and 919 MW of DR capacity in the 2020/2021 summer and winter period, respectively.[16]

However, none of this capacity has been needed or used. It is not needed to meet reliability standards based on current and near-term conditions.[17] The most recent planning figures from the IESO show there is no need for new capacity – based on current reliability standards and planned capacity additions – in the winter months until the 2022/23 commitment period.[18] Only under an extreme scenario would there be a small need for new capacity in the summer months in the 2020 timeframe. Furthermore, the DR capacity purchased has never been activated to provide any energy services, including to provide emergency backup resources when other resources fail.[19] Unlike assets under long-term contracts or rate regulation, DR

[15] Ontario has been in a surplus capacity position for more than a decade based on a review of 18-month Reliability Outlook documents.

[16] See the IESO's DR post-auction report for the Summer 2020 and Winter 2020/21 period: http://reports.ieso.ca/public/DR-PostAuctionSummary/PUB_DR-PostAuctionSummary_2020.xml

[17] The most recent planning document, the Annual Planning Outlook, shows no capacity need in 2020. The IESO's Transitional Capacity Auction charter refers to the 2018 Technical Planning Conference, which previously showed a capacity need in 2020 of 811 MW (summer adequacy: reference outlook without existing resources). The IESO has recently shifted to referencing the Reliability Outlook to inform the capacity need – an outage planning document that shows a potential capacity shortfall under extreme weather conditions during summer 2020 – however the IESO has indicated that the Annual Planning Outlook will inform procurements. For more information on the Annual Planning Outlook, see: http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Annual-Planning-Outlook-Jan2020.pdf?la=en

[18] See the IESO's DR post-auction report for the Summer 2019 and Winter 2019/20 period: http://reports.ieso.ca/public/DR-PostAuctionSummary/PUB_DR-PostAuctionSummary_2019.xml

[19] As of January 2020.

capacity is procured on an annual basis and that procurement can easily be reduced simply by reducing the demand curve in the DR Auction.[20]

The DR Auction has been in operation since 2016 and has continually increased the amount of capacity procured at each successive auction. To date, ratepayers have paid more than $213 million for capacity that is not required to meet current reliability standards. The Panel has argued that the DR procurement should be scaled back until it is actually needed to meet peak demands.

Hourly Demand Response Resources

In a recent presentation, the IESO stated that certain types of DR capacity – namely those resources that are not able to respond to five-minute price signals – are only intended to be used on “very rare days” when additional energy is required to meet system needs. These DR resources are known as Hourly Demand Response (HDR) and account for a majority of all DR capacity procured in the auction – 78% of all DR capacity procured in the most recent auction.[21] These resources participate in the energy market by submitting bids priced between $100/MWh and $1,999/MWh, with most bids being in excess of $1,500/MWh. Given such extremely high bid prices, the likelihood of HDRs being activated to meet their capacity obligations is negligible, and in the past such resources have never been used. Essentially, HDRs are utilized as “emergency” resources. Notwithstanding, to date, they have received more than $157 million in payments for undertaking to be available to balance supply and demand in the market when called upon.

[20] See the IESO presentation, “Transitional Capacity Auction, Draft Phase I Design”, dated April 18, 2019: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/mocn/mocn-20190418-TCS-draft-phase1-design.pdf?la=en

[21] See the IESO’s DR post-auction report for the Summer 2020 and Winter 2020/21 period: http://reports.ieso.ca/public/DR-PostAuctionSummary/PUB_DR-PostAuctionSummary_2020.xml

The IESO recognizes that, given the current surplus in capacity and the rules developed for DR, the likelihood of activation for HDR resources has been – and continues to be – negligible. But this reality is clearly at odds with the announced purpose of the program. If the IESO is procuring HDR resources primarily for emergency purposes, it should make that clear in the design the DR Auction, or any future capacity auction.

In conclusion, the DR part of the market involves a competitive market, but all resources that might provide peak power are not competing in that market and some of the competing resources, specifically HDR resources, appear to provide a different function than the rest. The Panel welcomes the IESO's recent push to implement a capacity auction based on the DR auction, but open to other resource-types, namely gas generators with expired contracts, to improve the competitiveness of the DR Auction.

1.1.4 Competition in the Short-Term (Spot) Energy Market

The Panel views the energy market as reasonably competitive and efficient on a short-term basis. Market-based outcomes are currently achieved largely as a result of regulated or contracted incentives that seek to mimic incentives facing a merchant-based generation fleet fully exposed to the wholesale market. While these incentives seek to maintain the efficiency and competitiveness of the real-time energy market, they may be less effective than full exposure by Market Participants to the Market Clearing Price (MCP).

In Chapter 3: Matters to Report in the Ontario Electricity Marketplace, the Hydroelectric Incentive Mechanism (HIM) is discussed in some detail. The Panel concludes that while fixed-price rate regulation removes OPG's incentive to respond to spot price signals with its rate-regulated hydroelectric assets, the addition of the HIM essentially restores the incentive to offer those resources efficiently, as they would be offered by a merchant generator. Recently OPG's assets covered by the HIM have set prices in approximately 40% of the hours in the year.

Ontario's nuclear plants are either rate-regulated or subject to contract prices. In the current monitoring period, they set the MCP in less than 1% of all intervals (see Figure A-7 in Appendix A). Because marginal costs are very low, the Panel expects these plants to offer close to zero, but because shutdown is extremely costly for nuclear plants, they might offer very negative prices to ensure they are dispatched. Data shows that nuclear plant operators do often offer at negative prices.

Ontario's gas-fired plants are virtually all contracted. One class of gas plants, the non-utility generator (NUG) plants, operated under fixed-price contracts that encouraged them to maximize output regardless of the spot price or the need for their power. Most of these contracts have expired or been renegotiated to reduce the incentive to maximize output. Clearly these contracts did not encourage competitive or efficient operation in their time, but that time has nearly run its course.

A majority of gas-fired plants operate under Clean Energy Supply (CES) or "deeming" contracts. The contracts stipulate that when prices rise above the generator's variable costs, as described in the contract, they will be deemed to have run in the market and collected revenue at the market rate. The calculated operating profit (Hourly Ontario Energy Price (HOEP) less the generator's deemed variable costs) are clawed back from the contract payments – whether they in fact ran or not. This provides an incentive to offer the plant's actual marginal cost, precisely the efficient incentive.[22] This contract provision provides a price hedge to consumers and generators and can minimize GA costs. While the Panel does not have data on the fraction of all hours that gas plants subject to these contracts set prices, in the current monitoring period, gas plants in total have set prices about 33% of all intervals. The Panel

[22] Gas generators can offset some of this risk by utilizing the Real-time Generation Cost Guarantee (RT-GCG) program, which provides a payment to cover start-up and a portion of operating costs. For a detailed analysis of these contracts, see the Panel's Monitoring Report 10 (May 2007-Oct 2007) published August 2007, page 169: http://www.ontarioenergyboard.ca/documents/msp/msp_report_20080115.pdf

understands that at least 64% of gas plant capacity is subject to deeming contracts, so at least that fraction of gas plant capacity should be offering efficiently.[23]

Ontario's grid-connected variable generation plants are generally contracted with fixed-price contracts.[24] Because marginal costs are nearly zero, and thus far below the contract price, the Panel would expect them to offer a price low enough to be dispatched when available, including negative prices. Merchant wind and solar plants that do not receive a guaranteed, contracted or regulated rate would stop generating when the price dropped to zero or near zero. At times when Ontario has excess capacity, as it has for the last decade and likely will for a few more years, it is clearly inefficient to have zero-marginal-cost plants – that can easily shut down – offering negative prices that distort the market price.[25] In the current monitoring period, these variable generation plants have set the MCP in 22% of all intervals.

Overall, the Panel finds Ontario's short-run spot market to be reasonably competitive. The use of contract language analogous to the "deeming" provisions in some gas contracts would improve competition for those plants that are now on fixed-price contracts. The Panel urges the IESO to strive in all future contracting to ensure that the contract language is such that efficient marginal-cost bidding is maintained.

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[23] The largest thermal generator in Ontario – the 2,200 MW Lennox Generating Station – has a contract with the IESO. That contract has not been reviewed by the Panel. These figures are based on the IESO's active generation contract list, available at: http://www.ieso.ca/-/media/Files/IESO/Document-Library/power-data/supply/IESO-Active-Contracted-Generation-List.xlsx

[24] Total wind and solar capacity in Ontario under contract with the IESO is 8,209 MW (as of the third quarter of 2019). Most, if not all, of this capacity receives a fixed price for output, as stipulated by the contracts. For more information, see the IESO's "Progress Report on Contracted Electricity Supply" for the third quarter of 2019: http://www.ieso.ca/-/media/Files/IESO/Document-Library/contracted-electricity-supply/Progress-Report-Contracted-Supply-Q32019.pdf?la=en

[25] The IESO implemented floor prices for dispatchable wind and solar resources, ranging from -$3/MWh to -$15/MWh.

1.1.5 Ongoing Deficiencies of the IESO-Administered Markets and Market Renewal

The Panel has previously analyzed two well-known deficiencies in the IESO-Administered Markets that the IESO plans to resolve through the MRP: the Two-Schedule System and cost guarantee programs.

The MRP is a broad market reform to improve competition in existing markets in Ontario and introduce new competitive markets and mechanisms with the goal of improving economic efficiency. The MRP would:

- Replace the Two-Schedule System with a Single Schedule Market (SSM) and Locational Marginal Prices (LMP).
- Introduce a financially binding Day-Ahead Market (DAM).
- Replace the current cost guarantee programs with a more robust and competitive commitment mechanism.

The MRP moved from High-Level Design to Detailed Design during 2019.[26]

The Two-Schedule System, CMSCs and Uniform Pricing

The Two-Schedule System is a unique, Ontario-only approach for setting the MCP and determining which generators, dispatchable loads and imports and exports are dispatched to provide energy in the real-time energy market. It consists of two separate schedules – one to determine the price paid by all consumers across Ontario (uniform price) and another to determine what resources are actually dispatched to meet demand. The price-setting schedule assumes no transmission congestion or losses and that demand can be met by the most economical generation source, no matter where it is located. This schedule sets the province-wide MCP that customers pay and all generators receive except for the Congestion

[26] One of the initial objectives of the MRP was also to introduce a competitive capacity auction to procure certain types of new capacity. As indicated earlier, the IESO is not longer pursuing this through the MRP.

Management Settlement Credit (CMSC) explained below. The dispatch schedule then introduces the transmission constraints and re-dispatches generators at least cost while recognizing the physical constraints of the grid. These two schedules diverge when congestion exists or transmission losses are significant.

When the dispatch schedule requires a generator to deviate, up or down, from its dispatch set in the price-setting schedule, a CMSC pays them the difference between the MCP and their offer. The Panel has repeatedly criticized CMSCs for their lack of transparency and inefficiency. When the market was first designed, CMSCs were intended to ensure that generators comply with dispatch instructions from the IESO and maintain reliability, but their use has steadily expanded over time.

The Two Schedule System results in several inefficiencies.

- **General inefficiency**: The uniform price set in the Two-Schedule System encourages excess consumption in high-cost locations, and unnecessary conservation in low-cost locations. For example, transmission constraints limit the amount of low-cost power that can be transmitted from northern Ontario, which has had a generation surplus for a decade, to southern Ontario where costs are generally higher. Yet consumers are charged the uniform price, as if the lower cost supply from the north could reach the south. This inefficiently encourages high consumption in the south while northern consumers are charged the high average price despite ample lower-cost generation nearby.
- **Intertie inefficiency**: Energy traders buy energy at the uniform price and then sell it in a neighbouring market. But in some hours, the cost of generating that energy is higher than the uniform price, with generators made whole via a CMSC payment. The result is that energy traders can profit by purchasing Ontario energy below cost and selling it for more in a neighbouring market.
- **Investment inefficiency**: The Two-Schedule system distorts decisions on where new supply should be added. That decision should be based on prices that reflect the value

> of new generation, in short, locational prices. In areas with surplus capacity the price paid should be low to discourage new investment, while high-price areas should encourage new generation investment. The Two-Schedule System undermines this price signal, risking uneconomic decisions for new capacity or the ongoing maintenance of current capacity.

Replacing the Two-Schedule System with a Single-Schedule Market is a core element of the MRP. The High-Level Design of the energy stream of the MRP, approved in 2019, will replace the Two-Schedule Market with a SSM; introduce a DAM with financial commitment and introduce an Enhanced Real-Time Unit Commitment (ERUC). After years of criticizing the current market design and the resulting CMSC payments, the Panel welcomes the development of the energy stream design of the MRP. If this element of Market Renewal is completed in accordance with the High-Level Design, a significant improvement in the efficiency of the Ontario electricity market will be achieved. Even the most conservative estimates of the monetary costs and benefits of the SSM stream of Market Renewal show that it is a good investment.[27] The Panel continues to urge the IESO and stakeholders to move forward with the MRP and implement the much-needed improvements that were originally laid out in the benefits case.[28]

One element of the original SSM design was to apply LMP to loads. Extensive IESO discussions with stakeholders revealed resistance to this part of the proposal by major industrial loads and Local Distribution Companies (LDCs). In the end, the High-Level Design adopted a single province-wide zonal price for “passive” loads in Ontario (LDCs and other

[27] See the IESO presentation “Market Renewal Program Business Case”, dated September 24, 2019: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/mrpum/mrpum-20190924-mrp-business-case.pdf?la=en

[28] See the Panel’s comments on the updated benefits case figures, dated September 10, 2019: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/mrpum/mrpum-20190910-msp.pdf?la=en

loads that are not price responsive). Market Participants will be allowed to choose to pay the locational price at their node.[29] Insulating most loads from locational prices amounts to a risk mitigation scheme for large loads, the most sophisticated electricity consumers in Ontario. The Panel has commented in support of zonal pricing for all loads and regrets the loss of incentives for loads to look for ways to mitigate short-term zonal price excursions.[30]

Cost Guarantee Programs

The Panel has analyzed and made numerous recommendations regarding the IESO's cost-guarantee programs in addition to CMSCs. One program of particular concern has been the Real-Time Generation Cost Guarantee (RT-GCG). This program guarantees the recovery of certain costs by fossil-fueled, non-quick start generators (i.e. natural gas generators).

The Panel has consistently questioned various components of this program, ranging from whether the program was necessary, to what level of costs should be guaranteed by Ontario ratepayers. In its most recent analysis on the cost guarantee program, the Panel found the RT-GCG program was required in just 1% of committed hours to meet real-time domestic demand and OR – resulting in approximately $40 million in excess costs borne annually by Ontario ratepayers.[31] The Panel also found that Ontario ratepayers were subsidizing tens of millions of dollars annually in guarantee costs that should have been paid by exporters.[32] The Panel has

[29] Dispatchable loads, which currently actively participate in the wholesale market, will pay the nodal price, not the uniform Ontario price.

[30] The Panel provided extensive comments to the IESO on its decision to abandon zonal pricing for loads. For more information, see the Panel's submission to the IESO from July 2019: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/mrpum/mrpum-20190702-market-surveillance-panel.pdf?la=en

[31] See the analysis in the Panel's Monitoring Report 27 (May 2015-Oct 2015) published November 2016: https://www.oeb.ca/oeb/_Documents/MSP/MSP_Report_May2015-Oct2015_20161117.pdf

[32] See the analysis in the Panel's Monitoring Report 23 (May 2013-Oct 2013) published September 2014: https://www.oeb.ca/oeb/_Documents/MSP/MSP_Report_May2013-Oct2013_20140924.pdf

on multiple occasions urged the IESO to expand the range of wholesale market revenues that should be used to offset the guarantee payment, while limiting the guarantee to fuel costs and little else. All of these recommendations would improve the efficiency of the wholesale market, while reducing costs for Ontario ratepayers.

Nearly all of these recommendations remain unaddressed to date. The ERUC stream – in combination with the DAM – of the MRP is intended improve the commitment process for thermal generators by considering all costs, such as start-up and other costs, not just energy offers.[33] The Panel has recommended the IESO adopt such an approach. While the Panel is encouraged by the High-Level Design of the ERUC process, it will continue to monitor the program through the Detailed Design and implementation stages. Nonetheless, the implementation of these changes will not occur until 2023 at the earliest, raising the question whether the IESO should undertake interim solutions as recommended by the Panel.

1.1.6 The Transmission Rights Clearing Account

The IESO is in the process of implementing a recommendation from the Panel regarding the distribution of funds from the Transmission Rights Clearing Account (TRCA).

In the Panel's Monitoring Report 28 (Nov 2015-Apr 2016) published May 2017, the Panel recommended that the IESO revise the methodology by which it disburses funds from the TRCA. The Panel recommended that disbursements from the TRCA be based on the share of transmission costs paid by domestic load and exporters, not based on the share of demand. In its report, the Panel estimated that $51 million of the $58 million of TRCA disbursements to exporters should have gone to Ontario transmission customers, which would have had the effect of lowering transmission rates in Ontario. In the same report, the Panel also

[33] See the IESO's early presentation "Introduction to (ERUC)", dated October 11, 2017, and the "(ERUC) High-Level Design" document, dated August 2019: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/eruc/ERUC-20171011-Introduction.pdf?la=en and http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/eruc/ERUC-High-Level-Design-Aug2019.pdf?la=en

recommended that the IESO not disburse any money from the TRCA until such time as the revised disbursement method is implemented.

The IESO agreed with the Panel's recommendation, but continued to make disbursements until it completed a review and presented its proposal to stakeholders. Since the recommendation nearly three years ago, the IESO has made six disbursements totaling nearly $497 million.[34] Ontario customers received $429 million in disbursements from the TRCA, but would have received $486 million under the Panel's proposal – a difference of $57 million. Export customers received $68 million in disbursements from the TRCA, but would have received $11 million. The IESO engaged in a stakeholder process considering the IESO's proposal to distribute the TRCA surplus to Ontario consumers only and in January 2020 the IESO announced a decision to implement the change for the December 2020 disbursements.[35]

1.1.7 Updates on the Competitiveness and Efficiency of the Energy Market

A recent development regarding the competitiveness and efficiency of the IESO-Administered Markets is increased consolidation of assets by the largest – and provincially owned – Market Participant, OPG. In July 2019, OPG announced its proposal to purchase TC Energy's combined cycle natural gas-fired generating stations in Ontario (the Napanee Generating Station (GS), the Halton Hills GS and the remaining 50% stake in Portlands GS), as well as its proposal to purchase the remaining 50% stake in the combined cycle Brighton Beach GS from affiliates of Canadian Utilities Limited. With these transactions, which have now closed,

[34] As of January 2020.

[35] See the IESO presentation to the Market Development Advisory Group (MDAG) "Transmission Rights Clearing Account Disbursement Methodology Review", dated January 21, 2020: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/mdag/mdag-20200121-presentation-trca.pdf?la=en

2,693 MW of thermal generation came under OPG's 100% control.[36] The OEB has granted Portlands Energy Centre a licence amendment to include the Napanee GS and Halton Hills GS, and in doing so has also added conditions in both that licence and in OPG's licence to mitigate the OEB's concerns related to market power.

The acquisitions result in OPG having 100% control of 48% of the market's installed capacity, as well as the increased ability to trade in and out of the province on the interties.[37] The increased consolidation of assets by OPG – and the increased risk for it to exert market power – introduces an additional concern for the competitiveness of the wholesale market. The Panel's analysis looks at the history of OPG's market power since the market opened in 2002, and at what the recent acquisitions might mean for OPG's market power in the OR market when analyzed under a traditional monitoring metric.

Market Power and Mitigation

In the run-up to market opening, OPG owned as much as 90% of all installed capacity.[38] The original Market Design Committee (MDC) was concerned that such market power had the potential to stifle competition in the new market and distort prices, and felt the need to address the issue notwithstanding the Province's ownership of OPG. In an attempt to reduce the

[36] The transaction to acquire assets from affiliates of TC Energy closed on April 29, 2020, with the assets now being owned and operated by Portlands Energy Centre L.P. The transaction to acquire the remaining stake in the Brighton Beach Generating Station was completed in August 2019.

[37] Installed capacity data for OPG and Ontario was provided by the IESO on February 12, 2020 and is consistent with the Annual Planning Outlook (January 2020) base case, including only the capacity that participates in the real-time energy market. Data referenced as "pre-acquisition" refers to the total capacity of OPG-owned assets from the Annual Planning Outlook base case, excluding assets from the acquisitions. Data referenced as "post-acquisition" refers to the total capacity of OPG-owned assets including assets from the acquisitions.

[38] The market was initially expected to launch in 2000, but was delayed until 2002. By 2001, OPG had signed a long-term lease on its Bruce Nuclear Generating Station to transfer operations to Bruce Power, which reduced OPG's control of installed capacity to around 70% at market opening.

publicly-owned utility's market power, the Market Power Mitigation Agreement (MPMA) was recommended in 1998.

The MPMA contained two key elements. First, it capped the price paid to OPG on 90% of its domestic sales at $38/MWh. Secondly, it required OPG to reduce its generating capacity to 35% of Ontario's total capacity over the next decade and to reduce its control of price-setting generating plants to 35% of the Province's total within 42 months. The MPMA was implemented through a Directive to the OEB regarding conditions to be included in the licences issued to OPG and others.[39] The Panel, in its first major review of the IESO-Administered Markets, highlighted the ongoing concern of OPG's market power, saying that as "long as OPG remains a dominant supplier in the market its ability to influence price will be a source of uncertainty to potential competitors".[40]

The MPMA has over time been largely overtaken, including by reason of giving the OEB the authority to set OPG's rates (referred to as "payment amounts") starting in April 2008. OPG now receives a regulated rate for output from all its assets not under contract, while assets under contract receive a contracted rate.[41] If wholesale market revenues are greater than its regulated or contracted rates, OPG rebates that money to ratepayers; if there is a shortfall, ratepayers make up the difference.[42] If rate regulation could perfectly mimic competitive outcomes, market power would not be an issue. But rate regulation is never perfect, so there is

[39] The March 24, 1999 Directive that implemented MPMA was followed by successive Directives that required the OEB to modify certain conditions of OPG's licence and to eliminate others (including the de-control provisions). For more information on the MPMA, see the Directive from the Minister of Energy, Science and Technology to the OEB: https://www.oeb.ca/oeb/_Documents/Documents/Directive_to_the_OEB_19990324.pdf

[40] See the Panel's Monitoring Report 3 (May 2002-Oct 2003) published December 2003: https://www.oeb.ca/documents/msp/panel_mspreport_imoadministered_171203.pdf

[41] A number of OPG's hydro and natural gas assets are under contract with the IESO, rather than being under OEB rate regulation. The assets included in the recent acquisitions from TC Energy and Canadian Utilities Limited are all under contract with the IESO.

[42] The differences between wholesale revenues and regulated or contracted rates are reflected in the Global Adjustment. The Global Adjustment has only been a credit to ratepayers on two occasions since 2006.

still some public benefit to avoiding excessive market power to reduce the opportunities to achieve higher than competitive prices.

OPG's share of installed capacity has never been reduced to the level contemplated in the de-control provisions of the MPMA (which have since been deleted from OPG's licence further to a Ministerial Directive). OPG's share of total assets was reduced by the leasing of the Bruce GS several years ago, the sale of some hydroelectric assets and the shuttering of the coal plants. However, with the recent acquisitions, the share of the Province's generation under OPG's control – particularly its share of price-setting capacity – has grown. This seems at odds with some of the goals of Market Renewal, particularly improving market efficiency and competition.

OPG's Installed Capacity in the Wake of the Acquisitions

With the purchase of the TC Energy and Brighton Beach gas assets, OPG controls nearly 50% of dispatchable gas capacity and nearly 50% of total installed capacity in Ontario – significantly above the 35% threshold contemplated at the time of market opening. Table 1-1 below shows OPG's market shares pre- and post-acquisitions.

Table 1-1: OPG Capacity, Pre- and Post-Acquisitions[43]

	pre-acquisitions OPG (% of installed capacity)	post OPG acquisitions (% of installed capacity)
OPG gas capacity as compared to total gas capacity	26%	48%
OPG total capacity as compared to total capacity	42%	48%

[43] Data is based on installed capacity of Market Participants as of February 2020. A small percentage – less than 10% – of installed gas capacity is non-dispatchable, meaning they are price takers as opposed to price-setters. If these assets are excluded from these figures, the share of price-setting gas assets controlled by OPG after the acquisitions would increase.

Pivotal Supplier Test

One way to understand a Market Participant's ability to exert market power is to use a Pivotal Supplier Test (PST). The Panel offers this analysis not as dispositive of the market power issue but illustrative, as one of several commonly-used means of measuring that power. A PST measures the ability to meet demand when output from the largest supplier is removed. When the ratio of the PST is below 1.0, there is a pivotal supplier that may be able to exert market power (shown in the following example) and impact the MCP. In a simplified example, if demand for a particular hour is 1,000 MWh and there is 1,500 MWh of available supply, with the largest supplier providing 600 MWh of output, then it is considered a pivotal supplier.

- **a.** Pivotal Supplier Test = (Total Available Supply – Output by largest supplier) / Total Demand
- **b.** 0.900 = (1,500 MWh – 600 MWh) / 1,000 MWh

In most electricity markets, regulators and market monitors employ what is known as a two or three PST – combining the output of the two or three largest suppliers. Given the concentrated nature of the market, with OPG now controlling nearly 50% of installed capacity, the Panel simply performed the analysis as a single PST in the OR market – a clear example of how concentrated the market is compared to other wholesale electricity markets.

Applying the PST to the OR markets, the number of hours in which OPG would have been able to exert market power in 2018, had the acquisitions been completed at that time, would have increased from 1% to 7% (+6%) for the 10S market, from 35% to 56% (+21%) for the 10N market, and from 1% to 3% (+2%) for the 30R market.[44] More concerning would have been the potential for OPG to raise the OR MCP in those hours. For example, prior to the acquisitions, the MCP in hours when OPG was a pivotal supplier was $20.74/MWh. But if the assets in the acquisitions are included, the number of hours would increase by 543 hours

[44] See the flexibility analysis in Chapter 3 for a detailed description of the OR markets.

(+6%). In those 543 hours, the MCP was $11.77/MWh, meaning OPG could, as a result of the acquisitions, potentially exert market power and raise the MCP to $20.74/MWh – marking a near 80% increase in the MCP in 6% of all hours in 2018.

Table 1-2: OPG as Pivotal Supplier of OR, Pre- and Post-Acquisitions

OR Class	Total Hours	Pre-Acquisitions Hours when OPG is Pivotal Supplier	Post-Acquisitions Hours when OPG is Pivotal Supplier	Increase in Hours with the acquired facilities	Average MCP ($/MWh) for 2018	Pre-Acquisitions Average MCP ($/MWh) when OPG is Pivotal Supplier	Average MCP ($/MWh) in Hours when OPG would have been Pivotal Supplier with the acquired facilities
10S	8,760	1% (71 hrs)	7% (614 hrs)	+6% (+543 hrs)	$7.37	$20.74	$11.57
10N	8,760	35% (3,085 hrs)	56% (4,925 hrs)	+21% (+1,840 hrs)	$5.65	$10.71	$4.42
30R	8,760	1% (76 hrs)	3% (223 hrs)	+2% (+147 hrs)	$2.88	$15.39	$10.77

The Panel recognizes that the market is unique and that our PST analysis applies only to the OR market. No other competitive electricity market has either the concentration of assets under the control of one (publicly owned, nonetheless) Market Participant whose rates are set by contract or rate regulation. While these out-of-market mechanisms may mitigate the ability of OPG to exert market power, they may not eliminate it altogether. By increasing its dominance in installed capacity – both baseload and peaking assets – the potential risk of the exercise of market power, in the Panel's view, becomes more of a concern.

Setting the MCP for Energy

Another concern is that with control of nearly 50% of price-setting capacity, OPG has greater market power in days when system conditions are tight and thermal generators generally set the MCP. The Panel provides an example to illustrate.

On August 19, 2019, thermal units in Ontario set the MCP in more than 200 five-minute intervals – or around 70% of all intervals in the day. OPG's thermal assets set the MCP in just 14% of all intervals if the recently-acquired assets are not counted. Had OPG controlled the recently-acquired assets at the time, the number of intervals in which its thermal assets set the MCP would increase to 98 intervals, or 34% of all intervals on that day.[45] The Panel recognizes that this day is not illustrative of a typical day in the energy market, but rather an example of a day when market demand is higher than average with a greater opportunity for higher MCPs to be set by peaking thermal units.

Table 1-3: OPG Assets Setting Market Clearing Price, Pre- and Post-Acquisitions on August 19, 2019

Date	5-minute Intervals OPG thermal assets set MCP before acquisitions	5-minutes intervals OPG thermal assets would have set MCP with the acquired assets	% increase	% of 5-minute intervals OPG thermal assets set MCP before with the acquired assets	% of 5-minute intervals OPG thermal assets would have set MCP with the acquired assets
August 19, 2019	41	98	139%	14%	34%

[45] This analysis assumes that, prior to the transactions, the 50% stake that OPG owned in the Portlands and Brighton Beach gas plants were operated independently of OPG.

1.1.8 OEB Licence Conditions

On April 9, 2020, the OEB issued a Decision and Order in respect of an Application by Portlands Energy Centre (PEC) to amend its electricity generator licence to reflect the acquisition of the two generation facilities acquired from TC Energy. The OEB granted the Application, but in doing so also imposed conditions not only in PEC's licence but also in OPG's licence to address the OEB's concerns about market power.[46] The amended licences require that OPG and PEC make decisions on offering supply into the electricity market independently of each other, and that they offer all their respective generating resources into each of the OR markets, the Day Ahead Commitment Process and the energy market. OPG and PEC are required to negotiate an agreement with the IESO to monitor and report on the implementation of this must-offer condition and an *ex post* monitoring program. The Panel is reassured by the licence conditions that have been imposed by the OEB to address concerns about market power and the competitiveness of – and confidence in – the wholesale market, and the Panel expects to monitor performance under those conditions.

1.1.9 The Industrial Conservation Initiative

The Industrial Conservation Initiative (ICI) continues to allocate out-of-market costs in a manner that encourages inefficient behaviour. In 2018, the Panel provided an in-depth review and criticism of the ICI program.[47] No material change has been made to the design of the program since that report was released.[48]

The ICI is, at the most basic level, a peak-shaving and cost allocation mechanism. The impact of the program on shifting costs between customer classes has been – and continues to be – significant. Between 2011, when it was first introduced, and 2017, the ICI shifted nearly

[46] See the OEB Decision and Order dated April 9, 2020 (EB-2019-0258 / EB-2020-0110): http://www.rds.oeb.ca/HPECMWebDrawer/Record/674020/File/document

[47] See the Panel's Industrial Conservation Initiative Report published December 2018: https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

[48] As of January 2020.

$5 billion in electricity costs from large to small-volume consumers. In 2017 alone, the ICI shifted $1.2 billion in electricity costs to households and small businesses – nearly four times greater than the amount in 2011. In 2017, the ICI increased the cost of electricity for households and small businesses by 10%.

In principle, the ICI could efficiently encourage large loads to reduce demand during peak hours – helping to reduce price spikes during those hours. However, the current design of the ICI program – in combination with a low-price environment and high Global Adjustment (GA) charges – creates an uneconomic and inefficient incentive to reduce demand when there is ample supply and capacity. The per-MW incentive to reduce peak demand in recent years is as much as five times greater than the cost of adding peak capacity to the system. It therefore provides a perverse incentive to install behand-the-meter capacity – which often costs more than grid-connected peaking plants – at a time of surplus capacity across the province. Conversely, if Ontario did not have excess supply, Hourly Ontario Energy Price (HOEP) would be higher, GA charges would be lower (they are inversely related) and the ICI would present little incentive for loads to reduce demand. In short, the ICI offers the strongest incentive to conserve in years when supply is ample and the weakest incentive in years when supply is tight.

The ICI also leads to concerns around fairness, as it has allowed some large loads to avoid paying much – or any at all – GA charges in recent years, even though the costs that give rise to the GA are predominantly related to non-peaking assets.

The Panel remains of the view that only the cost of peak generation should be recovered through peak demand charges, while non-peak costs should be allocated such that all consumers who benefit from that capacity pay for it.[49]

[49] For more detail on how the market efficiency and fairness of the ICI can be enhanced, see the Panel's Industrial Conservation Initiative Report published December 2018: https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

1.2 Developments Related to the IESO-Administered Markets

This section summarizes other developments related to the IESO-Administered Markets that the Panel considers noteworthy.

1.2.1 Activation Payments for DR Resources

Both the OEB and the IESO have considered the question of providing payments to DR resources (activation payment) when they are economically activated in the real-time energy market.[50] While DR programs have been an ongoing part of Ontario's electricity market for many years – ranging from early Ontario Power Authority (OPA) programs launched in the years following market opening to the current DR Auction overseen by the IESO – the introduction of an activation payment as currently proposed by some Market Participants would be a new development in the IESO-Administered Markets.[51] Similar policies have been introduced under different circumstances in some electricity markets in the United States.[52]

The OEB's consideration of activation payments came as a result of an application by an industrial consumer representative, the Association of Major Power Consumers in Ontario (AMPCO), regarding market rule amendments made by the IESO in early September 2019

[50] Economically activated means being dispatched based on their bids – i.e. their bids are "economic".

[51] See the IESO Demand Response Working Group' presentation "Demand Response Programs in Ontario", dated April 3, 2014: http://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Working-Groups/-/media/files/ieso/document-library/working-group/demand-response/drwg-20140403-DRWG-OPA-Presentation.pdf

[52] See Federal Energy Regulatory Commission Order 745: https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

with an effective date of October 15, 2019.[53] The market rule amendments would expand the DR auction to include non-DR resources – mostly a small number of non-regulated generators with expired contracts – and rebrand it as a “capacity auction” going forward.[54] AMPCO argued that expanding the DR Auction to include traditional generators would unjustly discriminate against DR resources, as DR resources are not eligible to receive the wholesale market price when they are activated in the real-time energy market.[55] In contrast, when a generator sells its output, it is paid the market price for that output. DR resources – if activated and required to reduce consumption – only avoid paying the market price for that reduced consumption. AMPCO argued that energy payments to generators provides an additional source of revenue that might enable these participants to lower their offers in the capacity auction, placing DR resources at a competitive disadvantage. AMPCO also applied to stay the operation of the market rule amendments pending the OEB’s final determination of the matter. The OEB granted that application, which prevented the capacity auction from proceeding in early December 2019 as originally planned by the IESO. As a result, in December 2019 the IESO proceeded with another DR Auction (excluding all other types of resources), ultimately procuring a greater amount of DR capacity from a year earlier and – for the first time since the DR Auction was launched in 2016 – at a higher clearing price than the previous year.[56]

[53] On an application to review a market rule amendment, the OEB’s task is to determine whether the market rule amendment is unjustly discriminatory or inconsistent with the purposes of the *Electricity Act, 1998.* In this case, a principal argument made by AMPCO was whether the market rule amendments relating to the IESO’s “Transitional Capacity Auction” (as it was then called) were unjustly discriminatory due to a lack of payments to DR resources when they are activated.

[54] See the IESO’s presentation to its Board of Directors regarding the changes, “Market Rule Amendments: Transitional Capacity Auction”, dated August 28, 2018: http://www.ieso.ca/-/media/Files/IESO/Document-Library/mr-amendments/mr2019/MR00439/TCA-Rule-Amendment_Board-presentation.pdf?la=en

[55] See AMPCO’s Notice of Motion, dated September 26, 2019: http://www.rds.oeb.ca/HPECMWebDrawer/Record/653721/File/document

[56] See the IESO’s DR post-auction report for the Summer 2020 and Winter 2020/21 period: http://reports.ieso.ca/public/DR-PostAuctionSummary/PUB_DR-PostAuctionSummary_2020.xml

In January 2020, the OEB denied AMPCO's application, concluding that there was insufficient evidence to make a finding that the market rule amendments – which open the DR Auction to non-DR resources –"unjustly discriminate against or in favour of a Market Participant or class of Market Participants".[57] The IESO responded to the Decision with an announcement that the first auction to include non-DR resources was planned for June 2020. The auction has since been deferred until the fourth quarter of 2020.

The IESO launched a stakeholder engagement and hired a consultant to consider whether DR resources should receive an additional payment when activated economically.[58] The Panel has submitted comments to the IESO as part of the stakeholder process, encouraging it to provide clear objectives on what it is hoping to achieve, establish a set of principles to guide its decision-making process and provide an analysis on the whether the Federal Energy Regulatory Commission (FERC) order mandating energy payments has any application in Ontario given the unique structure of Ontario's electricity market.[59]

As the Panel noted in its comments to the IESO, the market has a long history with price-responsive loads. It is not clear that the objectives laid out by FERC in its energy payments ruling are appropriate in Ontario. FERC was explicitly attempting to remove barriers for loads to participate in the wholesale energy market. But in Ontario most loads either pay the

[57] See the Decision and other documents related to the hearing (EB-2019-0242): http://www.rds.oeb.ca/HPECMWebDrawer/Record?q=CaseNumber%3DEB-2019-0242&sortBy=recRegisteredOn-&pageSize=400

[58] The IESO subsequently expanded the scope of this stakeholder engagement to also consider whether DR resources should be paid shut-down costs or any other payments to cover activation costs.

[59] See the Panel's comments regarding "Energy Payments for Economic Activation of Demand Response Resources", submitted November 18, 2019, and comments regarding "Energy Payments for Economic Activation of Demand Response Resources – Shut-Down Cost Options", dated June 1, 2020: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/epdr/epdr-20191025-market-surveillance-panel.pdf?la=en and http://ieso.ca/-/media/Files/IESO/Document-Library/engage/epdr/epdr-20200611-market-surveillance-panel.pdf?la=en

wholesale price for energy – as opposed to a retail rate as is common in FERC-regulated markets – or can participate in the wholesale market as a dispatchable load or as an HDR resource. The barrier to entry from participating in Ontario's wholesale energy market is already low for DR resources.

The IESO expects to complete the stakeholder process by the summer of 2020, and implement changes by March 2021.

1.2.2 Changes to the OR Market

In March 2019, the IESO launched a stakeholder engagement that it said would address a number of the Panel's concerns regarding the OR market.[60] The Panel's recommendations regarding the OR market were two-fold: first, some Market Participants, particularly dispatchable loads, were being paid for OR that they were incapable of providing and second, that the IESO should claw back OR payments made to Market Participants if those participants failed to fully respond to an OR activation.

As part of a stakeholder engagement, the IESO has proposed two changes. It will review the Market Rules and Manuals to ensure the performance of Market Participants in the OR market is evaluated on the incremental energy provided during an activation. This change, if implemented as proposed, will require Market Participants to compare their OR activation with their previous energy dispatch to determine the incremental amount of energy they are required to provide. The IESO also proposes to implement after-the-fact claw backs from Market Participants for any payments made for scheduled OR that the resource was incapable of providing.[61]

[60] See the list of Panel recommendations and IESO responses that covers the status of actions taken by the IESO response to Panel recommendations over a rolling 5-year period (Jan 2015-Dec 2019): http://www.ieso.ca/-/media/Files/IESO/Document-Library/market-assessment/IESO-2019-OEB-Status-Update-Report.pdf?la=en

[61] For example, if a Market Participant has a maximum output of 100 MW, with 80 MW scheduled in the energy market and 20 MW, but was generating at 90 MW in the energy market, it could only provide 10 MW of OR.

Ultimately, the IESO's proposals address only one of the Panel's recommendations – that dispatchable loads (and other Market Participants) not be paid for OR they are incapable of providing. For dispatchable loads, this will be achieved by clawing back OR payments when their consumption is below the scheduled amount of OR. For generators, this will be achieved by clawing back OR payments when the difference between output and maximum capacity is less than scheduled OR.

But the Panel's other recommendation related to clawing back payments made to OR Market Participants when they fail to fully respond to an activation remains unaddressed. The IESO's proposed solutions do not address the current materiality threshold for claw backs regarding OR, which has been set at zero, and there is no mention of changing the OR activation claw back formula. In fact, the IESO explicitly states that the proposed OR claw backs will "not be triggered by OR activations" and will only pertain to scheduled OR. The Panel's initial analysis estimated that, assuming the materiality threshold was set to zero – where every failure to fully respond to an OR activation was considered for a claw back – that the IESO could have recovered more than $12.5 million in OR payments for the period January 2010 to April 2016. The IESO's proposed solutions ensure that it will continue to pay Market Participants for services they could not provide.

1.3 Status of Recent Panel Recommendations

Below are the recommendations made in the Panel's Monitoring Report 31 (May 2017-Oct 2017) published in December 2019 and the IESO's responses to them.[62]

Table 1-4: Status of Recent Panel Recommendations and IESO Responses

Recommendation	IESO Response
Recommendation 2-1 **The IESO should consider ways and means of deterring the Operating Reserve nodal price chasing behaviour described in this report.**	*Response letter re Panel's 31st Monitoring Report (January 13th, 2020)* The IESO agrees with the Panel that instances of overcompensating an Operating Reserve supplier will be resolved with the implementation of the Single Schedule Market through the elimination of Congestion Management Settlement Credit payments and the introduction of Locational Marginal Pricing. In the interim, the IESO intends to undertake an assessment of potential interim solutions that could address the issue, prior to the implementation of the Single Schedule Market. The IESO will share the results of its assessment with the Panel by the end of Q1 2020.
Recommendation 2-2 **The IESO should ensure its procedure for determining an outage when administering Transmission Rights aligns with the Market Rules.**	*Response letter re Panel's 31st Monitoring Report (January 13th, 2020)* The IESO accepts the Panel's recommendation. The IESO agrees with the Panel that Transmission Rights (TR) payouts should not be made on a TR path for which the transmission transfer capability has been reduced to zero. In response to the Panel's finding, the IESO will be making the required changes to IESO processes and systems. The IESO is developing a project plan to complete the required changes and will update the MSP on its progress by the end of January 2020.

[62] See the letter from Peter Gregg, President and CEO of the IESO, to Robert Dodds, Vice- Chair of the OEB, dated January 13, 2020: https://www.oeb.ca/sites/default/files/IESO-MSP-Ltr-OEB-20200113.pdf

	Memorandum to Panel (January 31st, 2020) The IESO is working towards developing an enduring solution which the IESO expects to implement by the end of Q3 2020. However, in the interim, to ensure that no TR payouts are made on a TR path for which the transmission transfer capability has been reduced to zero, the IESO will implement a temporary settlement solution by the end of Q1 2020. The IESO will communicate the temporary solution to stakeholders before implementing any change that impacts TR market participants, and the timing for the temporary and enduring solutions is subject to any feedback that the IESO may receive from TR Market Participants in response to IESO's notification of a change to TR payouts.
Recommendation 3-1A **The Panel recommends that-when implementing changes to the market-the IESO audit the pre-deployment testing process to ensure that sufficient controls are in place to identify errors and unintended consequences.**	*Response letter re Panel's 31st Monitoring Report (January 13th, 2020)* The IESO agrees with the Panel that a review of the IESO' s testing and deployment practices for implementing change would be of value. As part of the IESO's commitment to having robust change management processes when implementing changes to market systems the IESO uses a structured System Development Lifecycle (SDLC) process. The SDLC process includes a testing phase which occurs after a new system is built or when changes to an existing system are made, and before it is implemented. In 2017, the IESO introduced significant improvements to strengthen the IESO's testing practices. In particular, a Quality Assurance (QA) team was established to consistently ensure that quality is assessed, verified and validated throughout project delivery and SDLC processes. The QA team creates testing plans for projects. Depending on the project, the use of external auditors may be recommended. The IESO' s Internal Audit business unit, which reports to the Board of Directors, is scheduled to undertake a review of the QA and deployment function in 2020.

Recommendation 3-1B **The Panel recommends that, as soon as possible after the IESO detects an error or unintended consequence that significantly impacts the wholesale electricity market, it publically discloses details of the error or unintended consequence, the impact on the market and the actions taken or to be taken to address the matter.**	*Response letter re Panel's 31st Monitoring Report (January 13th, 2020)* The IESO accepts the Panel's recommendation that after detecting an error or unintended consequence that impacts the wholesale electricity market, the IESO should take appropriate action to publically disclose the matter as soon as possible once the IESO has assessed the matter and understands what is needed to address it. In response to the recommendation, the IESO will review its current practices to report publically on IESO significant or material errors. The objective of the review is to assure that there are policies, processes or guidelines (e.g., materiality guidelines) to publically report IESO significant errors. The IESO expects to complete this review by Q2 2020.

1.4 Panel Commentary on IESO Response

The Panel acknowledges the IESO's commitment to address these recommendations and looks forward to the IESO's proposed solutions.

Chapter 2: Analysis of Anomalous Market Outcomes for the Winter 2017/18 Period

2.1 Introduction

This chapter examines the market outcomes associated with anomalous prices and payments during the Winter 2017/18 Period (November 1, 2017 to April 30, 2018) and drawing comparisons to the Winter 2016/17 Period (November 1, 2016 to April 30, 2017) as appropriate.

Traditionally, the Panel's analysis of anomalous events has focused on high and negative Hourly Ontario Energy Prices (HOEP), as well as instances of significant Congestion Management Settlement Credit (CMSC) payments, Operating Reserve (OR) payments and Intertie Offer Guarantee (IOG) payments, all of which are recovered from Ontario consumers and exporters through uplift charges.

The HOEP is Ontario's wholesale price for electricity. It is calculated as the simple hourly average of the five-minute Market Clearing Prices (MCPs) which are derived in real-time based on energy offers and bids. The Panel tracks this metric as it is a reflection of the prevailing supply and demand conditions in the Ontario wholesale electricity market. The Panel considers a HOEP higher than $200/MWh or below $0/MWh to be an anomalous price.

CMSC is an out-of-market payment made to dispatchable resources. Typically, CMSC is paid when, as a result of system constraints, the IESO's dispatch instructions to these resources differ from the dispatch instructions they would have received had the constraints not been present. The Panel tracks anomalous CMSC payments in order to understand whether such payments are appropriate given the prevailing system conditions. The Panel's thresholds for anomalous CMSC payments are $1,000,000/day and/or $500,000/hour.[63]

[63] The Panel's views and concerns regarding CMSC have been well documented, most recently in the Panel's Congestion Payments Report published its December 2016, available at: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_CMSC_Report_201612.pdf

OR is stand-by power or demand reduction that can be called on with short notice to deal with an unexpected mismatch between generation and load. The IESO is required to maintain OR in order to meet its reliability obligations. Like the MCP, prices for OR are derived in real-time every five minutes based on OR offers from qualifying dispatchable resources. The Panel tracks OR payments as these often reflect supply conditions in the Ontario wholesale electricity market. The Panel's threshold for anomalous OR payments is $100,000/hour.

IOG is an out-of-market payment made to importers. In Ontario, imports and exports are locked-in based on hour-ahead pre-dispatch prices, but settled based on real-time prices. IOG payments are made when the settlement price is below the importers' locked-in hour-ahead offer price. The Panel tracks anomalous IOG payments to understand the variability of supply and demand between pre-dispatch and real-time as well as the commitment of imports at various intertie zones. The Panel's thresholds for anomalous IOG payments are $1,000,000/day and/or $500,000/hour.

Table 2-1 displays the number of events that exceeded the Panel's thresholds during the Winter 2017/18 Period. Figures from the previous relevant reporting period (Winter 2016/17 Period) are also included.

Table 2-1: Summary of Anomalous Events (Number of Events)

Anomalous Event Threshold	Number of Events	
	Winter 2017/18 Period (Nov 2017-Apr 2018)	Winter 2016/17 Period (Nov 2016-Apr 2017)
HOEP > $200/MWh	4	20
HOEP ≤ $0/MWh	650	1,065
CMSC > $1 million/day	3	0
CMSC > $500,000/hour	1	0
OR > $100,000/hour	7	24
IOG > $1 million/day	3	0
IOG > $500,000/hour	7	0

The Winter 2017/18 Period saw four high-price hours: December 14, Hour Ending (HE) 9; January 6, HE 18; January 15, HE 21; and April 1, HE 20. Variable generation shortfall (300 MW on average) was the main factor contributing to high prices in all cases except for the January 15 event. In addition, the December 14 and the January 6 events saw failed imports (420 MW on average), while the latter and the April 1 event also had under-forecasted demand (135 MW on average). The January 15 event already had an anomalously high pre-dispatch price ($414/MWh), likely a result of a forced 290 MW de-rate of a gas generator. This high price actually decreased in real-time as a result of real-time demand averaging 300 MW less than forecast.

The 650 low-price hours occurring during the Winter 2017/18 Period can be explained by low prevailing demand.

The circumstances leading to high HOEP hours also explain four of the high OR payment hours, due to the co-optimization of the two markets. The three remaining hours occurred on November 23, HE 9; January 14, HE 9; and March 16, HE 19. For these events the HOEP was also high ($164/MWh on average), but below the Panel's threshold. Factors contributing to these high prices were generally the same as described above. The November 23 and the March 16 events had variable generation shortfall (395 MW on average) and under-forecasted demand (170 MW on average). The November 23 event also had 500 MW of failed imports. The January 14 event was caused by supply problems. Two gas generators failed to synchronize to the grid while two other gas generators were de-rated by approximately 300 MW.

High CMSC payments occurred on three days during the Winter 2017/18 Period. Approximately $2.1 million was paid on January 4 and approximately $1.3 million on each of January 14 and February 3.

On January 4, the number of gas generators that were committed for the Real-Time Generation Cost Guarantee (RT-GCG) and the Day-Ahead Production Cost Guarantee (PCG) was higher than the month’s average due to high forecasted demand. In real-time, however, the demand was over-forecasted for a number of hours throughout the day by an average of 1,000 MW and in certain hours an average of 200 MW of exports did not materialize. In addition, internal transmission constraints led to approximately 100 MW of exports to Manitoba being constrained off for several hours. These factors contributed to approximately $700,000 in constrained-on CMSC being paid to gas resources, approximately $550,000 in constrained-off CMSC being paid to hydro resources, and approximately $385,000 in constrained-off CMSC paid to Manitoba exporters. The remaining CMSC payments were made mainly on the Minnesota intertie. About half of the payments were to constrained-on importers and the rest to constrained-off exporters. Payments to the latter were generated in a three-hour window after the last pre-dispatch for each of the hours.

On January 14, $804,000 in CMSC payments were made in HE 7. In this hour, 703 MW of the 883 MW exports scheduled were constrained off between the final pre-dispatch run and real-time, almost all due to internal transmission constraints. Had these exports been curtailed before pre-dispatch, no CMSC would have been paid on account of the 2015 market rule amendment eliminating constrained-off intertie CMSC. In addition, approximately $230,000 in constrained-off CMSC was paid throughout the day to a single hydro resource due to a transmission constraint.

On February 3, a 600 MW shortfall in variable generation necessitated the IESO to constrain on multiple resources throughout the day. The most significant payment, totaling approximately $170,000, was to a single gas generator. In addition, an ongoing transmission outage resulted in a number of hydro resources being constrained on to respect system limits, contributing approximately $500,000 to the daily CMSC total.

All high IOG events occurred due to intertie congestion on the Québec interties as well as extremely low Intertie Zonal Prices. The congestion was a result of reduced intertie limits, generally for equipment reasons, while the low Intertie Zonal Prices were caused by strategically low import offers by Hydro-Québec to ensure that imports are scheduled in real-time. This issue was explored in detail in the Panel's Monitoring Report 31 (May 2017-Oct 2017) published December 2019.

2.2 Analysis of Other Anomalous Events

Anomalous events (market outcomes that fall outside predicted patterns and norms) do not necessarily result in high prices or large uplift payments, nor are they necessarily confined to a single hour or day. Since the Panel's Monitoring Report 29 (May 2016-Oct 2016) published March 2018, the Panel has expanded its analysis of anomalous events beyond those which meet or exceed pre-determined thresholds. Other criteria for assessing events include: the appropriateness of the market outcome relative to the market objective and the Market Rules, the novelty and frequency of an event, as well as the relevance of the outcome to current IESO initiatives and stakeholder engagements.[64]

The following section considers an anomalous event that occurred on January 22, 2018. In this case, the event resulted in a high price.

2.2.1 Incorrect Demand Forecast

On January 22, 2018, a one-time error in the IESO's demand forecasting tool resulted in a large discrepancy between pre-dispatch demand forecasts and real-time demand. This error only affected the unconstrained schedule and ultimately led to a price spike in the wholesale energy and OR markets.

The issue involved a certain function of the IESO's forecasting tool being turned off, resulting in the tool erroneously solving for the previous day's demand forecast values instead of the current day's.

[64] The objective of the IESO-Administered Markets is to promote an efficient, competitive and reliable market for the wholesale sale and purchase of electricity and ancillary services in Ontario.

What is Ontario's Two-Schedule System?

In Ontario, the wholesale electricity price – the Market Clearing Price (MCP) – is uniform. The MCP is set every five minutes based on offers to supply and bids to purchase electricity. The hourly average of the twelve MCPs is called the Hourly Ontario Energy Price (HOEP).

Ontario employs a unique method both to set the MCP and to determine which resources are dispatched to generate or withdraw energy in the real-time wholesale market. This method is referred to as a two-schedule system, as it utilizes an optimization program (Dispatch Scheduling and Optimization algorithm (DSO)) that is run in two modes: one to determine the uniform MCP and another to determine what resources are actually dispatched. The mode that determines the MCP is known as the unconstrained sequence, while the mode that determines what resources are dispatched by the IESO is known as the constrained sequence.

Unconstrained Sequence: In order to set the uniform price, the DSO runs the unconstrained sequence, which reviews all offers to supply and bids to consume energy assuming there are no physical constraints or limitations. The DSO stacks the offers from lowest to highest priced until the supply of energy matches demand. The unconstrained sequence produces the market schedule, which indicates how all dispatchable resources would be dispatched if there were no constraints and power could flow freely anywhere on the system.

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Constrained Sequence: The constrained sequence considers all physical and operational limitations affecting the IESO-controlled grid. The outputs of the constrained sequence are nodal prices and the dispatch schedule. The nodal prices represent the cost of energy at each injection and withdrawal point, but are produced for information purposes only. The IESO's dispatch instructions are based on the outputs of the constrained sequence.

Depending on the prevailing physical and operational limitations of the IESO-controlled grid, the IESO may dispatch resources that would be considered "uneconomic" in the unconstrained sequence. In the case of generators, this means that higher-priced units may be dispatched instead of their lower-priced alternatives. The IESO does this because it is considering physical or operational limitations that may prevent energy from a lower-priced unit from reaching certain consumers. When this occurs, the dispatch schedule set in the constrained sequence will dispatch units that would not have come online in the unconstrained sequence, which is based solely on economics and not the physical nature of the grid. In order to prevent the "uneconomically" dispatched units from operating at a loss, a unit that is dispatched "uneconomically" is paid an out-of-market payment known as a Congestion Management Settlement Credit (CMSC) based on the excess of their offer over the MCP that was set in the unconstrained sequence.

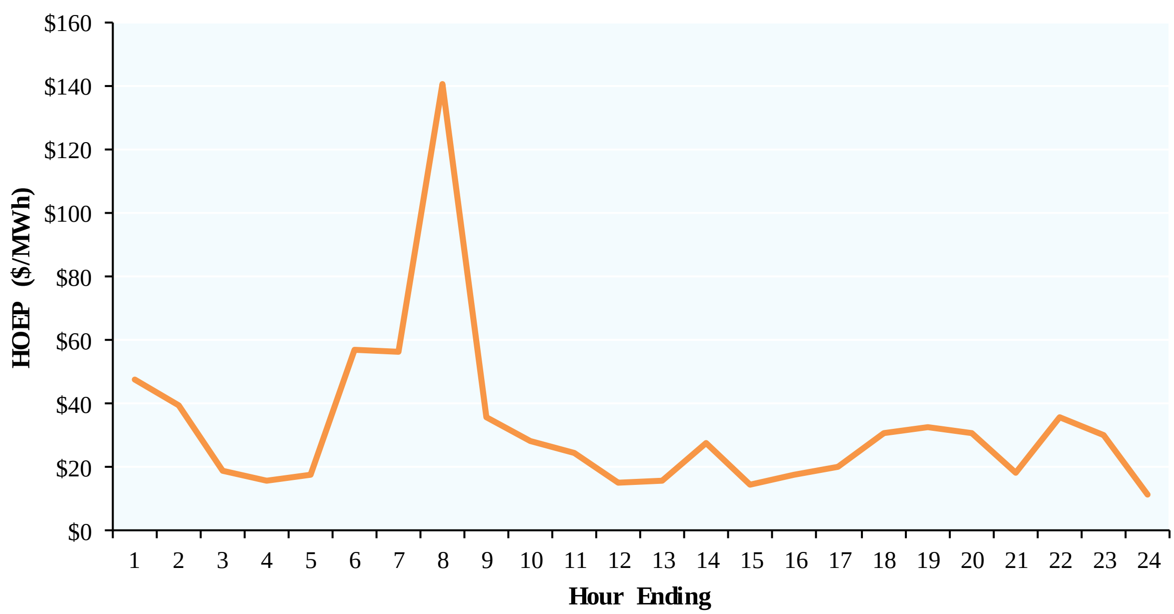
January 22 was a Monday, but due to the error, the IESO relied on pre-dispatch demand forecasts that were derived for a Sunday – a day on which energy consumption is typically much lower.[65] As Monday morning consumption levels increased hour-by-hour – as is typical

[65] The DSO was solving for demand forecast for January 21 instead of January 22 due to the hourly demand forecast flag being turned off in the Market Interface System (MIS), a key tool in determining pre-dispatch schedules. Typically, the MIS pulls 48 hours of primary demand data – the current and following day. But with the demand forecast flag being turned off, the demand forecast was being pulled for the previous day (Sunday) and the current day (Monday).

in the early morning hours of a business day in the winter months – the discrepancy between the pre-dispatch demand forecasts and the actual real-time demand widened. The gap became widest between 7 a.m. and 8 a.m.– referred to as Hour Ending 8 (HE 8) by the IESO. The last pre-dispatch demand forecast in the unconstrained schedule for that hour was more than 2,500 MW below real-time demand in the hour’s first interval, with the former being 13,893 MW and the latter being 16,402 MW. The wide divergence between the pre-dispatch demand forecasts and real-time demand affected resource scheduling in the unconstrained sequence of the DSO. The result was an upward pressure on the HOEP which contributed to it spiking to approximately $140/MWh in HE8. In contrast, the average HOEP for that week – considering only business days – was $25/MWh. Over the first eight hours of January 22, the average HOEP was $49/MWh, compared to $20/MWh over those hours on other business days in the same week.

The HOEP fell to approximately $35/MWh in the hour following the error being noticed and addressed by the IESO.

Figure 2-1: HOEP on January 22, 2018.



As the energy and OR markets are jointly optimized, OR prices were also affected. The 10-minute OR price, for example, increased from approximately $1/MW in HE 7 to approximately $45/MW in HE 8 – leading to more than $42,000 of OR-related payments in that one hour.

The major contributing factor to the price spike was the distorted pre-dispatch scheduling of intertie transactions. Intertie transactions are scheduled based on pre-dispatch forecasts and are locked-in real-time for one hour. Since the DSO was underestimating demand in the pre-dispatch unconstrained sequence, the pre-dispatch prices (including the Intertie Zonal Prices) were lower than they would have been had the demand forecast been accurate. This caused a significant quantity of imports to be considered uneconomic in pre-dispatch and not scheduled in the unconstrained sequence in real-time. At the same time, exports that would have otherwise been uneconomic were scheduled. In real-time, the higher than expected demand, along with the increase in scheduled exports meant that the price was set by higher-priced generators, thus causing a price spike.

The error affected only the unconstrained sequence of the DSO. While the demand forecast in both the constrained and unconstrained sequence begins with the same estimate, the constrained demand forecast is revised based on actual demand conditions. The unconstrained schedule, on the other hand, does not self-correct. As such, the imports that were not scheduled in the unconstrained sequence were nevertheless scheduled (constrained on) in the constrained sequence. Similarly, exports that were scheduled in the unconstrained sequence were constrained off in the constrained sequence. For HE 8, for example, approximately 900 MW of imports were constrained on and approximately 1,100 MW of exports were constrained off.

By HE 9, the IESO identified the demand forecast error and revised the forecasts for upcoming hours to more accurately reflect demand conditions. As a consequence, the scheduling of intertie transactions in the unconstrained sequence also became more accurate. Prices quickly returned to the range reflective of the prevailing supply and demand conditions.

It should also be noted that a likely secondary contributing factor to the price spike was variable generation shortfall. As the Panel discussed on numerous occasions in previous reports and also in the preceding section of this chapter, the variability of wind generation is often seen as one of the culprits in price fluctuations. For the hour in question, wind generation was approximately 360 MW below its forecasted value. Although such a distortion in supply could have led to a significant price increases on its own, for this particular event it was likely a secondary contributing factor. The following hour, HE 9, saw an even higher wind generation shortfall (approximately 420 MW), yet, as indicated above the HOEP decreased.

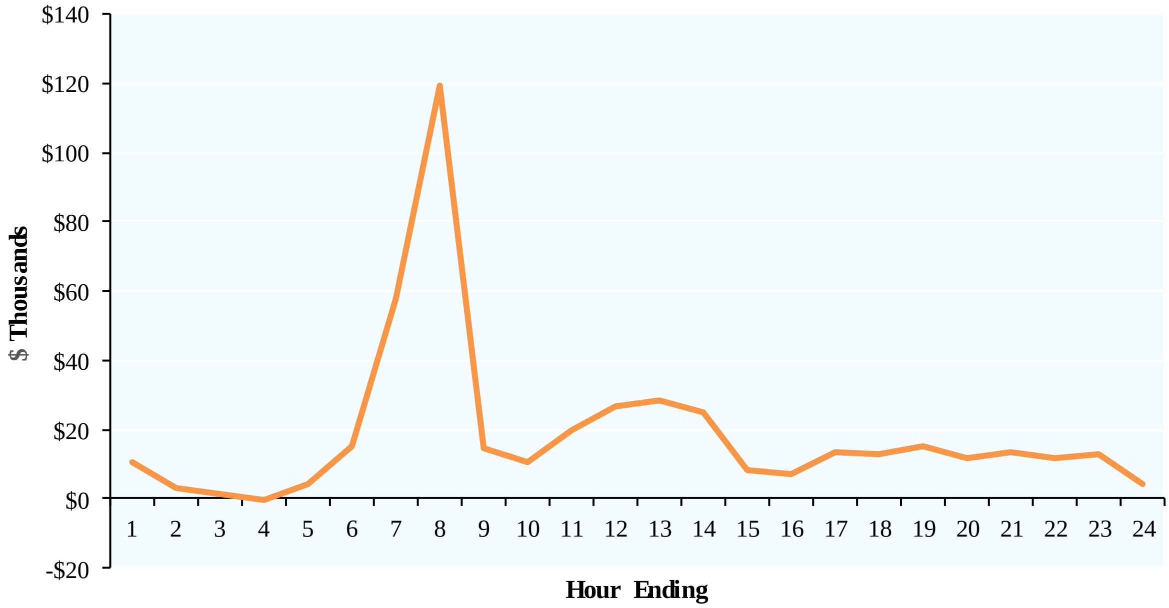
The price spike in HE 8 resulted in an increase in payments in the wholesale energy market as well as an increase in uplift payments. The Panel estimates that the combined impact of the price spike on wholesale energy market payments and uplift payments associated with transmission losses was between $1.7 and $1.9 million.[66] However, when considering the overall impact on system costs, at least some of the impact on the wholesale energy market would have been largely offset by a decrease in GA. However, as the Panel noted in previous reports, GA offsets due to increases in the HOEP do not affect all Market Participants in the same manner. Exporters, for instance do not pay GA, and Class A consumers typically pay a lower portion of GA compared to Class B consumers. The result is thus a wealth transfer between various groups of Market Participants.[67] This type of impact cannot be ignored as an impact of erroneous prices since some customers will have paid more and others less than they should have. Regarding the impact on other uplift payments, as indicated above, approximately $42,000 was paid out in OR-related payments; in addition, approximately

[66] This range was calculated by multiplying the average real-time demand computed in the constrained sequence during HE 8 by the difference between the actual HOEP during HE 8 and the Panel's estimate of what the HOEP would have been during that hour if the error in the IESO's demand forecasting tool did not occur. The Panel assumed that the HOEP during HE 8 would have been between $25/MWh and $35/MWh if the error did not occur.

[67] For a detailed discussion of how increases in the HOEP affect total system costs, see the Panel's Monitoring Report 31 (May 2017-Oct 2017) published December 2019, pages 37-39: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20191219.pdf

$120,000 was paid out in CMSC – with more than 85% of that CMSC being paid to one Market Participant.

Figure 2-2: CMSC Payments, January 22, 2018.



Overall, the demand forecasting error resulted in a price spike when real-time demand was significantly higher than the pre-dispatch forecasts, causing a distortion in the scheduling of intertie transactions. As a result, high-priced generators set the MCP. As the error only affected the unconstrained sequence, these high-priced generators were then constrained off in real-time resulting in CMSC payments. The price spike likely would not have materialized if the DSO error had not occurred, as prices quickly dropped once the IESO addressed the error in the forecasting tool.

Chapter 3: Matters to Report in the Ontario Electricity Marketplace

3.1 The Hydroelectric Incentive Mechanism

3.1.1 Executive Summary

OPG remains the largest owner and operator of hydroelectric assets in the province's wholesale electricity market, with these generators playing a pivotal role in producing energy during hours when it is most valuable and setting the MCP.

Effective April 1, 2008, the OEB set the regulatory rate, referred to as "payment amounts", for a portion of OPG's hydroelectric fleet, with additional hydroelectric facilities being brought under rate regulation since that date. At that time, OPG proposed and the OEB approved a Hydroelectric Incentive Mechanism (HIM), under which OPG could increase its revenue by reducing output during low-price hours and increasing output in high-price hours. The purpose of the HIM is to incent OPG to move production from periods of low value to periods of higher value, based on market signals.[68] In a subsequent proceeding the OEB required that 50% of the proceeds of the HIM be returned to customers and incorporated HIM revenues into the revenue requirement as a revenue offset.[69] Currently, rates for OPG's hydroelectric facilities are set using a price cap incentive rate-making methodology. The HIM and the revenue sharing mechanism remain in place.[70]

[68] As described in the later OEB Decision dated March 10, 2011 (EB-2010-008) setting payment amounts, pages 143-144, available at: https://www.oeb.ca/oeb/_Documents/Decisions/dec_reasons_OPG_Payment_20110310.pdf

[69] The OEB also adjusted the HIM through its review of the Surplus Baseload Generation deferral account, and noted its expectation that OPG use the pump generating station to the maximum extent possible to mitigate additional direct costs on ratepayers in respect of production that is lost due to surplus baseload generation.

[70] See the OEB Decision dated December 28, 2017 (EB-2016-0152), pages 121 to 134, and Payment Amounts Order dated March 29, 2018 (EB-2016-0152): http://www.rds.oeb.ca/HPECMWebDrawer/Record/595053/File/document and http://www.rds.oeb.ca/HPECMWebDrawer/Record/603940/File/document

The effectiveness of the HIM as an incentive for OPG to shift energy at its hydroelectric generators from low-value to high-value hours may have been weakened by structural changes in the wholesale market and diluted by the revenue sharing mechanism that was introduced in 2011.

Over the last decade, OPG has reduced the amount of energy it shifts from low value to high value hours. The reduced time-shifting is seen most clearly in two places. The use of the Pump-Generating Station (PGS) at the Sir Adam Beck hydroelectric facility on the Niagara River, which is intended to store water when electricity market prices are low and to generate when market prices are high, has diminished in recent years: average hourly output at PGS declined by 80% between 2010 to 2018.[71] Time-shifting of energy at OPG's other regulated hydroelectric assets has also declined over the past decade.

While there are likely several reasons for this decline, including lower on/off peak HOEP price differentials and higher water flows, it is essential to the integrity of the wholesale market that OPG has a clear incentive to use its hydroelectric assets efficiently. The same argument applies for any other hydroelectric generators with storage capability.

3.1.2 The Role of Price in the Wholesale Electricity Market

Ontario's competitive electricity market, like others in North America and around the world, is intended to improve the efficiency of the electricity system and lower costs for consumers.

Generators offer into the wholesale market and the system operator dispatches them in merit order until demand is satisfied. Generators are paid the MCP or spot price. In each five-minute interval, this system dispatches generators with the lowest offers. Each generator faces its own "marginal cost" of generating in an interval, based on its fuel cost, operating costs that may

[71] There are other indicators of reduced time-shifting, such as pumping costs and the associated production efficiency loss. When the market price difference is smaller than the cost of pumping, it is more efficient not to pump. Beck PGS was out of service between April 2016 and February 2017.

vary with output, the opportunity cost of water (in the case of hydroelectric generators) and other factors. In the absence of market power, a generator will maximize profits by offering its marginal cost in each interval. Thus, the process in a competitive wholesale electricity market automatically selects the generators with the lowest marginal costs for that interval, minimizing the cost of generation to consumers.

The efficiency of the wholesale market relies on generators having an incentive to offer their marginal costs. This incentive is clear to generators whose output is not paid on the basis of out-of-market contracts or rate regulation, and are not capable of exercising market power. However, contracts and rate regulation, which apply to most generation in Ontario, may provide payment that encourages a generator to offer into the spot market at prices that differ from their marginal cost. If a generator is paid a fixed price for every MWh of electricity generated, regardless of the spot price, the generator will compare its marginal cost with the fixed price. When its marginal cost is less than the fixed price, it will operate profitably, so it will submit an offer low enough – perhaps zero or negatively – to ensure it is dispatched. If its marginal cost is above the fixed price the generator will offer high enough, perhaps the maximum allowed offer price, to ensure that it is not dispatched because operating will cause a loss. The generator’s offers are related to a fixed price and will not generally equal its marginal cost. The spot price is therefore of secondary concern.[72]

Today, OPG’s hydroelectric generators are mostly rate-regulated, receiving fixed prices per MWh generated. This can lead to inefficient offers and reduce the contribution that hydroelectric generators can make to efficient market operation through the shifting of output from low-price to high-price hours. To the extent that OPG does not have an incentive to offer its marginal cost, its large fleet may distort Ontario’s wholesale market, increasing costs to

[72] OPG explained this outcome in its first rate application before the OEB. For more information, see the OPG Application to the OEB (EB-2007-0905), Exhibit I1, Tab 1, Schedule 1, page 8: http://www.rds.oeb.ca/HPECMWebDrawer/Record/40261/File/document

consumers. As described below, the HIM provides an incentive to OPG to make decisions based on market signals.

3.1.3 OPG's Hydroelectric Fleet

OPG remains the province's largest hydroelectric generator, owning and operating 54 rate-regulated hydroelectric stations with a generating capacity of more than 6,400 MW. This represents 17% of installed, transmission-connected generation capacity in the province, responsible for generating 22% of the electricity in 2018. OPG's regulated hydroelectric assets set the MCP in 40% of all five-minute, price-clearing intervals in 2018 and in nearly 42% of hours on average between 2014 and 2018. Clearly, the extent to which OPG has an incentive to offer its marginal or opportunity cost for the output of these hydroelectric assets is essential to the efficient operation of Ontario's wholesale market.[73]

The three types of hydroelectric generating assets in Ontario are baseload, peaking and run-of-river:

- **Baseload** hydro generators operate at nearly constant output, with limited storage ability capable of limited shifting of power from low to high value hours.
- **Peaking** hydro generators can shift a greater percentage of their output by storing water – with a storage horizon ranging from hours, to days to months. The amount and capability of storage varies depending on the generator, time of year and provincial water levels, among other factors. Peaking hydro generators will submit offers in the wholesale market that reflect the opportunity cost of water based on short- and medium-term water conditions and price forecasts. Pumped storage is a special type of peaking facility that can pump water up to a reservoir when prices are low and run it down again

[73] While OPG's rate-regulated hydroelectric assets account for the majority of installed hydroelectric capacity in Ontario, there are other hydro operators in the wholesale market. OPG itself, for example, owns a number of hydroelectric generators that are not subject rate regulation, but instead are under contract with the IESO. Brookfield also owns and operates hydroelectric generators under contract with the IESO. Contracted hydroelectric generators may have different incentives than the HIM.

to generate electricity when prices are high. OPG's 174 MW Sir Adam Beck PGS and its peaking generators were built specifically for such time-shifting.

- **Run-of-river** hydroelectric generators use water that is currently available, with little or no ability for storage.

3.1.4 Offers by Hydroelectric Generators

Hydro generators in a wholesale market maximize profits by submitting energy offers based on their short-term operating costs and their opportunity cost – i.e. the value of storing water for future sales based on current price forecasts. For hydroelectric generators, short-term operating costs largely consist of the Gross Revenue Charge (GRC) that includes provincially mandated water rental fees and property taxes. These costs are approximately the same per MWh whenever the plant is operated – making them largely irrelevant to a hydro operator's decision whether or not to store water. Opportunity cost is the value that could be earned by using water currently stored behind the dam at some later time. This is the driving force behind offer behaviour by peaking hydro generators and other units with storage capability.[74]

When there is ample water behind the dam or on the river system, an unregulated and uncontracted generator will reduce its offer to ensure dispatch, down to its marginal cost, which in Ontario would include water rental fees, among other charges.[75] In addition, high water conditions, among other factors, may impose physical constraints on hydroelectric generators, requiring them to run water through the turbines for environmental, safety or operational reasons – again leading to low-price offers to ensure dispatch. An abundant water supply lowers the opportunity cost of generating now so long as there is sufficient stored water or expected flowing water to take advantage of potential higher prices for future output. Conversely, when water is scarce – either in times of drought or when water storage levels

[74] For a more in-depth analysis, see the Panel's Monitoring of Offers and Bids Report published March 2010: https://www.oeb.ca/oeb/_Documents/MSP/MSP_Monitoring_Offers_Bids_Document_20100310.pdf

[75] Water rental fees are currently set by the Province at 9.5% of generator's gross revenue from annual output.

behind the dam are below capacity – hydro generators may increase offers to reflect water scarcity and the high opportunity cost of precluding generation in the future when prices are high. They will store water when they expect that stored water will earn a higher price in the near future.

Time-shifting of output based on these opportunity costs and some ability to store water results in opportunities for these generators to provide energy when it is most valuable to the system – when wholesale prices are high – and to reduce output and store water for future production when prices are low.

3.1.5 Rate Regulation of OPG Hydroelectric Generators

OPG receives an OEB-approved rate for output from its regulated hydroelectric assets – $42.51/MWh in 2019 and $43.15/MWh in 2020.[76] By itself, this regulated rate would, as indicated above, provide no incentive for OPG to offer at the marginal or opportunity costs of water. As described below, OPG is also subject to an OEB-approved incentive, the Hydroelectric Incentive Mechanism (HIM), that provides an incentive to OPG to shift energy output at its regulated hydroelectric assets from low-price to high-price hours. The incentive was found by the OEB to be an improvement on the then-existing mechanism as it leads to decision making based on the comparison of market prices.[77] OPG highlighted the importance of the HIM in its initial rate application:

> *"OPG's proposed hydroelectric incentive mechanism improves its operational drivers by tying all decisions (both operational and financial), regardless of hourly output, to market*

[76] See the OEB Decision dated December 13, 2018 (EB-2018-0243) and Payment Amounts Order dated December 12, 2019 (EB-2019-0209): http://www.rds.oeb.ca/HPECMWebDrawer/Record/628985/File/document and http://www.rds.oeb.ca/HPECMWebDrawer/Record/662340/File/document

[77] See the OEB Decision and Payment Amounts Order March 10, 2011 (EB-2010-008), page 55: http://www.rds.oeb.ca/HPECMWebDrawer/Record/256262/File/document

signals instead of the regulated rate. Using market signals is important to all Market Participants and to ratepayers as this will ensure that the operation of the regulated assets is optimized in all hours. Without an incentive mechanism tied to market signals, situations can occur where energy that could be transferred to peak hours is not transferred, or conversely, energy that could be transferred to peak hours is transferred contrary to what an efficient market would have dictated".[78]

OPG's hydroelectric fleet was not always rate-regulated. Prior to 2014, only six of OPG's assets – with a combined capacity of 3,312 MW – were subject to rate regulation: the Beck generating station units 1 and 2, the Beck PGS, DeCew Falls units 1 and 2 and R.H. Saunders. These were the initial "prescribed assets", and they were subject to rates prescribed by regulation from April 1, 2005 until April 1, 2008, and to rates set by the OEB thereafter. By July 2014, as a result of an amendment to *Ontario Regulation 53/05*, an additional 48 hydroelectric stations with a total capacity of 3,100 MW became subject to OEB rate regulation and were then referred to as the "newly regulated" hydroelectric facilities.[79,80] Prior to OEB rate regulation, these newly regulated assets received wholesale market prices.[81] In addition to the rate-regulated hydroelectric stations, several OPG hydroelectric stations are contracted with the IESO.

[78] See OPG's Application to the OEB (EB-2007-0905), Exhibit I1, Tab 1, Schedule 1, Page 10: http://www.rds.oeb.ca/HPECMWebDrawer/Record/40261/File/document

[79] See *O. Reg. 53/05, Payments Under Section 78.1 of The Act*, *Ontario Energy Board Act, 1998:* https://www.ontario.ca/laws/regulation/050053.

[80] See the OEB Decision (EB-2013-0321) dated November 20, 2014, pg. iii: https://www.oeb.ca/oeb/_Documents/Decisions/dec_reasons_OPG_20141120.pdf

[81] Prior to 2009, the non-prescribed assets (the 48 stations now under rate regulation) were subject to a provincially mandated "revenue limit" of $47/MWh on 85% of output, with OPG receiving market prices for the remaining 15% of output. This revenue limit meant that the effective marginal price faced by these assets was somewhat higher or lower than $47/MWh depending on whether the MCP was higher or lower than that amount in any interval. Those assets moved to full market-based revenue in 2009 and then to OEB rate regulation in July 2014.

3.1.6 The Hydroelectric Incentive Mechanism

While OPG continues to offer into the wholesale market and is paid the wholesale price for its output, the difference between rates set by the OEB and the wholesale price is recovered – or rebated if wholesale prices are higher than regulated rates – through the Global Adjustment (GA). In the end, OPG receives the regulated rate per MWh generated. Since, under this system, OPG ends up receiving the same revenue regardless of when it was generated, it offers no incentive to shift water from low-price to high-price hours.

To create a time shifting incentive, OPG proposed, and the OEB ultimately approved, the HIM. The HIM became fully effective in December 2008.[82] The intent of the HIM is to encourage OPG to hold back production in low-price hours and shift that production to high-price hours, while retaining much of the price security of the regulated rate. The HIM starts by calculating OPG's revenue (not profit) for each hour's output in that month at its regulated rate. It then adds or subtracts payment in each hour based on the deviation in output for that hour from the hourly average output (plus or minus), multiplied by the MCP for that hour. OPG can increase its revenues by reducing output when HOEP is low and increasing output by the same amount when HOEP is high: time-shifting.

The calculation of OPG's payments for rate-regulated hydroelectric generators through the HIM is as follows:

$$\sum_{t}[MWavg\ X\ RegRate + (MW(t) - MWavg)\ X\ MCP(t)]$$

[82] See the OEB Payment Amounts Order dated December 2, 2008 (EB-2007-0905): http://www.rds.oeb.ca/HPECMWebDrawer/Record/93959/File/document

Where:

MWavg *= The hourly average net energy production at rate-regulated hydroelectric generators for the month (MWh)*

RegRate *= The OEB-set regulated rate for hydroelectric assets ($/MWh)*

MW(t) *= The net hydroelectric energy production supplied into the IESO market for each hour of the month.*

MCP(t) *= The Market Clearing Price for each hour of the month.*

The first term in the equation *(MWavg X RegRate)* adds up to the regulated rate revenue for the month. The second term *(MW(t) – MWavg)* is the deviation in output in any hour t from the average, which can be positive or negative. This deviation is multiplied by the MCP(t), the market price in that hour. The sum for all hours in the month of the second half of the equation will be a positive addition to revenue if output is lower than average in low-priced hours and higher than average in high-priced hours. The more OPG shifts output from low-priced to high-priced hours, the more it benefits financially.

The following example shows the effect of shifting 100 MWh from a low-price ($10/MWh) to high-price ($100/MWh) hour assuming a regulated rate of $44/MWh:

Low-priced hour, reduce output by 100 MW, from 2,000 MW to 1,900 MW

- *MWavg = 2,000 MWh*
- *RegRate = $44/MWh*
- *MW(t) = 1,900 MWh*
- *MCP = $10/MWh*

$$[2000\ MWh\ X\ \$44/MWh + (1{,}900\ MWh - 2{,}000\ MWh)\ X\ \$10/MWh]$$
$$= \$87{,}000$$

High-priced hour, increase output by 100 MW, from 2,000 MW to 2,100 MW

- *MWavg = 2,000 MWh*
- *RegRate = $44/MWh*
- *MW(t) = 2,100 MWh*
- *MCP = $100/MWh*

$$[2000\ MWh\ X\ \$44/MWh + (2{,}100\ MWh - 2{,}000\ MWh)\ X\ \$100/MWh] = \$98{,}000$$

In this example, if OPG does not shift output, the revenue received from its regulated rate is (2,000 MWh X $44/MWh =) $88,000 in each of the two hours for a total of $176,000 for two hours. But by reducing output by 100 MWh in a low-priced hour and shifting that output to a high-priced hour OPG earns $87,000 in the low-priced hour and $98,000 in the high-priced hour, for a total of $185,000. This represents additional net revenue of ($185,000 – $176,000 =) $9,000.

Of central importance is that, while OPG can increase its revenues through the HIM, consumers will benefit, generally to a greater extent. The financial benefit of the 100 MWh shift in our example depends on the shape of the supply curve – which is upward sloping, at an increasing slope and is, generally, steeper the further up the offer stack – in those two hours.

Assume demand is 14,000 MWh in the $9/MWh hour and the slope is $1 per 100 MWh. Reducing hydro output by 100 MWh increases the price by $1/MWh to $10/MWh and results in a $14,000 increase in costs to consumers ($1/MWh x 14,000 MWh = $14,000). Further, assume demand is 20,000 MWh in the $110/MWh hour and the slope is $10 per 100 MWh. Increasing output by 100 MWh will reduce the price from $110/MWh to $100/MWh, saving consumers $200,000 ($10/MWh x 20,000 MWh = $200,000). While OPG has earned an extra $9,000 by shifting output between a low-price and high-price hour, energy costs were reduced by $186,000 ($200,000 – $14,000 = $186,000) – many times the OPG’s increase in revenue. This is a simplified example, the slopes could be different and the savings less than forecast here, but the slope is generally steeper at high prices than at low prices. In practice, contractual and regulatory arrangements for other generation facilities would essentially negate much of the savings in this example through the GA, but some consumer savings would survive.[83] Since the GA burden falls differently on different classes of consumers, getting the price right leads to a different allocation of cost than would otherwise be the case.

Shifting a MWh of output from an hour when prices are low to an hour when prices are higher increases OPG's revenue from that based on a flat, regulated rate. More importantly, the HIM ensures that the marginal incentive for OPG to move water is precisely guided by the expectation of spot prices in a given day or month, depending on storage capabilities and water conditions – similar to the incentive facing a merchant generator.

When the HIM was implemented in December 2008, it only applied to the six OPG hydroelectric assets that were rate regulated by the OEB at the time, with a total capacity of 3,312 MW. The HIM has since been applied as well to the newly regulated assets of OPG's hydroelectric fleet starting in July 2014, adding 3,100 MW of capacity subject to the incentive.

When the HIM was first proposed, OPG estimated that shifting production from low- to high-price hours would benefit consumers, as the price reduction in high-price hours would be greater than the price increase in low-price hours. OPG estimated that this time-shifting would reduce the average HOEP by between $0.40/MWh and $1.20/MWh for all electricity customers, with an annual estimated savings ranging between $80 million and $270 million.[84] OPG also expected that the new incentive mechanism would provide an "incremental incentive" of $5 million to $19 million to the utility, based on its 2009 market price forecast

[83] For other generators subject to fixed-rate contracts, any reduction in their market revenues would be offset by increases in GA payments.

[84] See the OPG Application to the OEB (EB-2007-0905), Exhibit I1, Tab 1, Schedule 1, Page 4: http://www.rds.oeb.ca/HPECMWebDrawer/Record/40261/File/document

range of $34/MWh to $57/MWh.[85] In short, OPG submitted that its response to the HIM would produce savings to consumers that were substantially greater than the increased profits for OPG.

In its 2010 rate application, OPG updated its HIM figures, estimating that HIM reduced average market prices by $1.14/MWh.[86,87] OPG submitted evidence that the forecast HIM revenue for 2009 was $12.0 million, but the actual HIM revenue was $23.2 million. The forecast HIM revenue for 2010 was $8.0 million, but the year-to-date actual at the end of August 2010 was $11.0 million.[88] OPG was generating more revenue than it expected via the HIM. OPG maintained that the HIM was working exactly as it should and it was shifting output via the PGS.

In the proceeding, intervenors in general submitted that OPG's incentive was excessive and that a sharing mechanism was appropriate. OPG, on the other hand, argued that any sharing mechanism would "reduce OPG's revenues from the HIM while leaving it with the same level of risk...[and] push OPG to operate with a flatter profile that it otherwise would".[89] OPG had previously argued against a sharing mechanism regarding HIM revenues, noting that any reduction in "the value of the incentive to OPG by introducing a revenue-sharing mechanism will increase the required price-differential. This, in turn, will reduce the number of occasions

[85] Ibid, Page 16.

[86] This application was to set rates for 2011 and 2012.

[87] See the OPG Application to the OEB (EB-2010-0008), specifically the "Production Forecast and Methodology – Regulated Hydroelectric", Exhibit E1, Tab 2, Schedule 1, page 2: http://www.rds.oeb.ca/HPECMWebDrawer/Record/195460/File/document

[88] Ibid, page 3.

[89] See OPG's Reply Argument for the Application for Payment Amounts (EB-2010-0008), page 28: http://www.rds.oeb.ca/HPECMWebDrawer/Record/233852/File/document

that time-shifting of the regulated hydroelectric production will occur, and thus reduce the much larger benefits to consumers that arise from a reduction in HOEP during peak-periods”.[90]

Ultimately, the OEB found that OPG had not substantiated its claim of consumer benefits and that, until a more robust incentive structure is established, 50% of the HIM revenues should be returned to consumers.[91] Accordingly, effective March 2011, OPG’s revenue requirement was offset by one half of the forecasted HIM revenues earned from time-shifting at hydro generators (adjusted for the interaction between HIM and Surplus Baseload Generation) – effectively counting half of the forecast HIM revenue up-front and potentially reducing the incentive for OPG to engage in time-shifting. At the same time, the OEB used that forecast as a threshold above which 50% of any incremental incentive payments from HIM would be shared equally with ratepayers through a deferral account.

OPG suggested making changes to the HIM. The OEB found that the then-existing HIM had encouraged appropriate use of the hydroelectric facilities to supply energy in response to market prices and that OPG failed to demonstrate that its new proposal was superior in terms of incentives for OPG or benefits to ratepayers, and that there was no compelling reason to change the revenue sharing ratio.[92]

If OPG’s HIM revenue forecast was based on the current year HIM revenue, the imputation of half that forecast to the next year’s revenue would act like a 50% tax on HIM revenue, delayed one year. This would seriously degrade the efficiency benefits of the HIM. The Panel notes that

[90] See the OPG Application to the OEB (EB-2007-0905), Exhibit L, Tab 1, Schedule 88: http://www.rds.oeb.ca/HPECMWebDrawer/Record/40261/File/document

[91] See the OEB Decision with Reasons and Payment Amounts Order dated March 10, 2011 (EB-2010-0008), page 147: http://www.rds.oeb.ca/HPECMWebDrawer/Record/256262/File/document

[92] The OEB did approve a change in the HIM calculation that accounted for double-counting that may occur as a result of Surplus Baseload Generation (SBG). For more information, see the OEB Decision with Reasons dated November 20, 2014 (EB-2013-0321), pages 12 and 13: http://www.rds.oeb.ca/HPECMWebDrawer/Record/456585/File/document

the forecast has not been changed since 2013. If the forecast is unchanged, the imputation will have no effect on current year behaviour; it would appear to OPG as a fixed cost. Keeping the forecast unchanged for a few years at a time would likely eliminate the risk that this sharing would degrade the efficiency benefits. Moreover, OPG's forecast is more likely to be based on expectations of water flows, the market price of electricity and other factors independent of the current year HIM revenue. In this case, the imputation would not diminish the efficient HIM incentive.

On the other hand, sharing 50% of HIM revenue above the threshold is effectively a 50% tax, reducing by 50% the incentive to shift output. If shifting hydro generation from a low-price hour to a high-price hour was costless for OPG, the OEB's reduction of the HIM incentive by 50% might matter little. However, shifting is not costless, especially at PGS. First, there is the cost of pumping water at the PGS facility – a cost that is not included in the HIM formula. Overall, the energy generated at the grid meter is as low as half of the energy required to pump the water up the hill.[93] If the losses were exactly 50%, it would be profitable to use the PGS only when the high price when generating was at least twice as great as the low price when pumping, a 2:1 price spread. Here, the absolute value of the electricity price does not matter, it is the relative prices that drive the profit or loss. Reducing the OPG effective share of the HIM revenue by half would render some profitable PGS shifting opportunities unprofitable. Secondly, and relevant to all OPG facilities with storage capability, there is risk in shifting output from one hour to another, as the forecast prices may fail to materialize. Any time OPG time-shifts water there is a risk and thus a cost associated with that decision. Thirdly, there are costs arising from some operator and staff time and attention and some mechanical wear and tear associated with moving the works that change hydroelectric output, and in addition for the PGS, OPG is obligated to pay market-based non-energy load charges for energy consumed to pump and GRC on the energy generated. All of these costs mean that when OPG's HIM

[93] If the pumped water runs through the PGS alone, only 50% of the pumping energy is recovered. If the water can also run through Beck II, up to 90% can be recovered. The result depends on water conditions at Beck II.

revenue is cut in half, OPG may give up opportunities for time-shifting that would be both profitable for OPG and cost-saving for consumers. In that case, the efficiency gains from HIM would be diminished.

3.1.7 Trends in Time-Shifting at OPG Hydroelectric Plants

HIM Revenue Trends

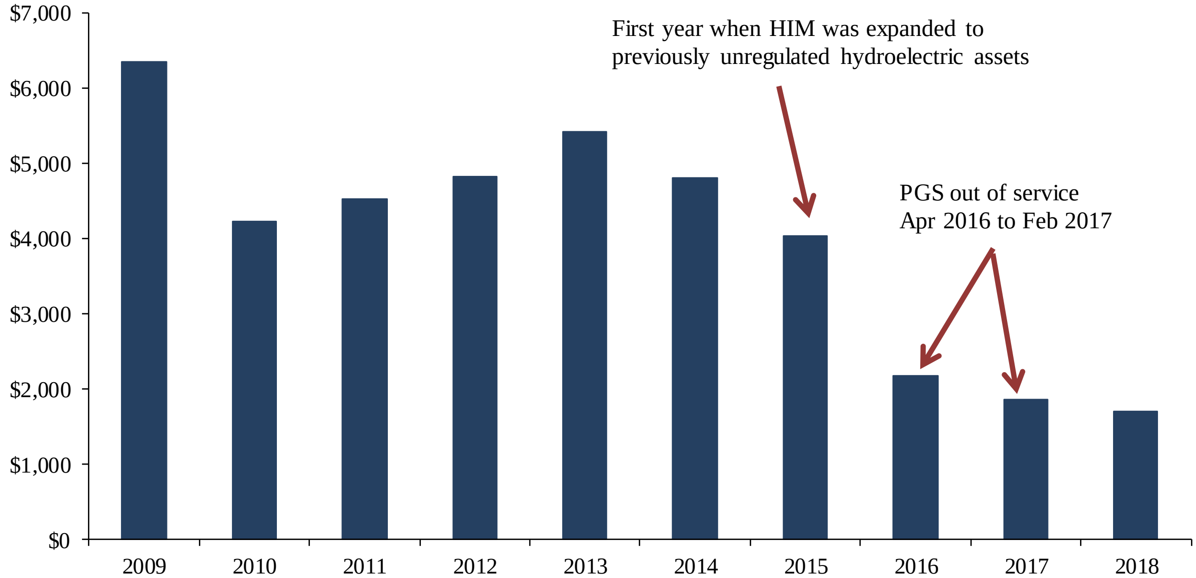
The revenue generated from the HIM mechanism has consistently fallen since 2009, the first full year it was in place. While there was a spike in gross HIM-related revenue in 2015, that marked the first full year when it was applied to most of OPG's hydroelectric fleet, amounting to more than 6,000 MW of capacity, compared to 3,300 MW of capacity previously. By 2018, HIM-related revenue had dropped to $11 million, or nearly half the amount earned in 2009, even though the capacity of the hydroelectric fleet capable of earning HIM revenue had nearly doubled. HIM revenue per MW of regulated hydroelectric capacity, a better measure of the incentive effect of HIM, has fallen by more than 70% from $6,360/MW in 2009 to $1,712/MW in 2018, as shown in Figure 3-1.[94]

In discussions with the Panel and during proceedings before the OEB, OPG provided explanations for why revenues from HIM have declined in recent years. First, OPG noted that the "value of the actual drivers and actual conditions" that underpin the HIM mechanism have changed from previous years.[95] OPG stated that there has been a lower spread between peak and off-peak prices, although the Panel notes that this spread has been fairly constant since 2010. OPG also noted that in order for a hydroelectric generator to operate profitably, the peak spot price must be greater than its fixed costs, which include water rental fees, among other charges that range from around $5/MWh to $14/MWh.

[94] The figures for HIM come from OPG's annual reports.

[95] See the OPG Responses to Interrogatories dated November 19, 2018 (EB-2018-0243) relating to the 2019 Hydroelectric Payment Amount Adjustment and Clearance of Deferral and Variance Account Balances, Exhibit L, H-Staff-3: http://www.rds.oeb.ca/HPECMWebDrawer/Record/626532/File/document

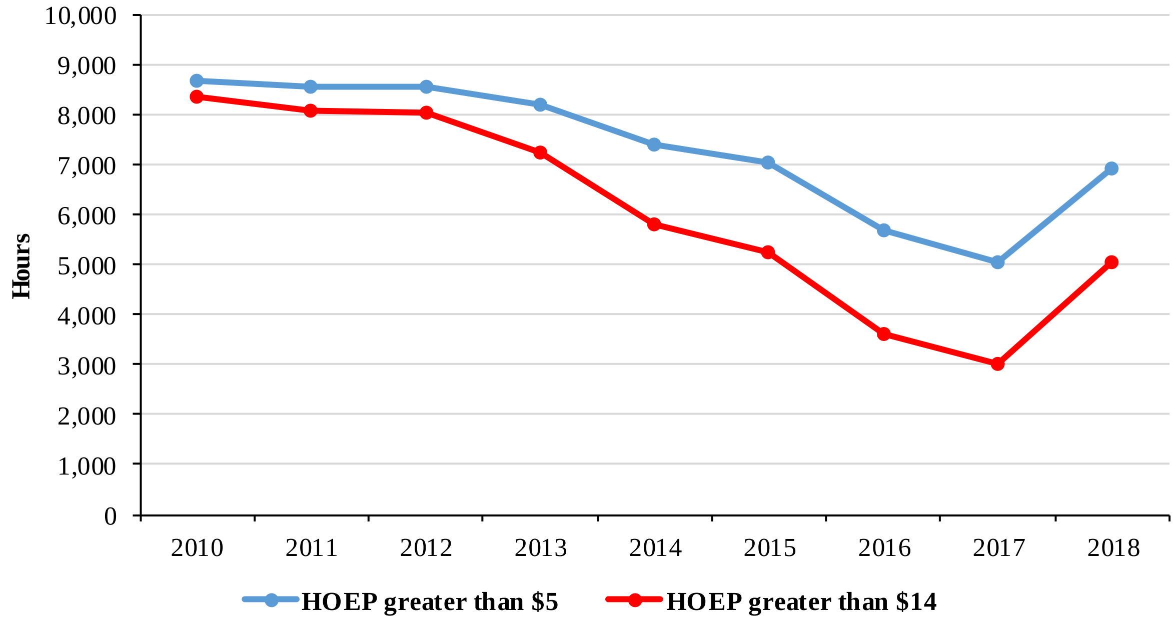
Figure 3-1: HIM Net Revenue per MW of Regulated Hydro Capacity



The Panel agrees that the number of hours where HOEP is below that threshold has increased significantly in recent years as shown in Figure 3-2 – therefore also significantly reducing the number of hours that OPG can target for time-shifting. Furthermore, high water conditions in recent years mean that there is less opportunity to store water – the reservoirs are often full, particularly at the Beck complex where PGS is located.

There have also been more hours with Surplus Baseload Generation (when baseload generation is higher than demand) which renders generation unprofitable.

Figure 3-2: Hours When HOEP is Greater Than Fixed Water Charge



Additionally, in discussions with the Market Assessment Unit (MAU), OPG noted that the forecast for HIM revenues was made in 2013 and has not been updated since then by either OPG or the OEB. In the ensuing years, actual HIM revenues have fallen significantly short of those forecast in 2013 so that the imputed revenue offset has exceeded HIM revenues. Based on actual HIM payments, OPG has not generated enough incentive payments to cover the first 50% of the HIM forecast since at least 2016. This means that in recent years OPG would be better off financially without the HIM mechanism and the 2013 forecast. However, to abandon it would abandon the incentive to offer their water efficiently.

That revenues have been well below the 2013 forecast also means that the sharing of revenues above the forecast threshold could not have had the effect of diluting the incentive. However, in future, changing circumstances could increase HIM revenues so that the sharing threshold is reached. The Panel believes that the design of the HIM should be robust to all plausible future conditions.

PGS Operation Trends

Over time, OPG's time-shifting of power at its hydroelectric generators from low-value hours to high-value hours has declined, most notably with the decrease in output at the PGS. The spread in output during high-priced hours compared to low-priced hours at its pre-2014 prescribed assets has also declined, though less notably, in recent years.

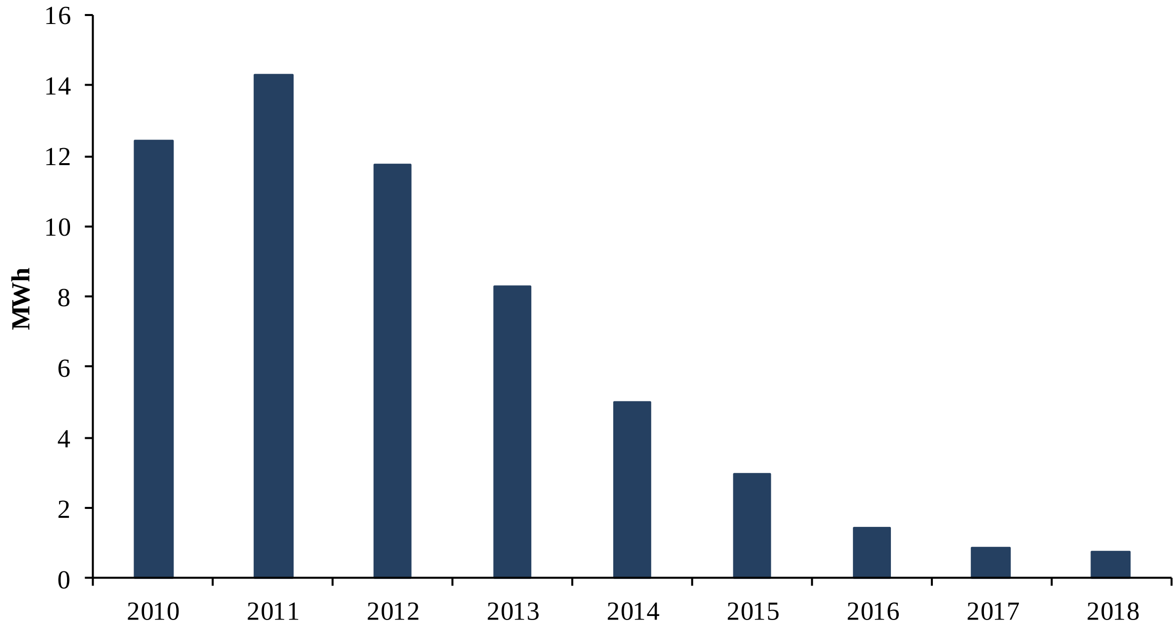
The PGS was built at the same time as the 1,499 MW Sir Adam Beck II generating station, commissioned in 1957. The PGS pumps water uphill into a 750-acre storage reservoir during low-price hours when the price of power needed to pump water is cheapest. When electricity prices are high, typically during peak demand hours, the water in the storage reservoir is released, generating power at the turbines connected to the PGS, with a combined capacity of 174 MW, as well as increasing output at the Beck I and Beck II generating stations. OPG refers to PGS as "Canada's largest and most flexible energy storage facility," noting that it can "store about the same amount of energy as 100,000 batteries that power electric cars".[96] In 2016, OPG spent $60 million refurbishing the reservoir, taking it out of service from April 2016 to February 2017.

But in recent years, OPG's use of the PGS has declined greatly. The average hourly generation at the PGS was nearly 13 MWh in 2010, but dropped to below 1 MWh in 2018, as shown in Figure 3-3.[97]

[96] Ontario Power Generation Inc., "OPG investing $60M refurbishing Niagara reservoir", Cision/Newswire, June 3, 2016: https://www.newswire.ca/news-releases/opg-investing-60m-refurbishing-niagara-reservoir-581773131.html

[97] Average hourly output is the output in the unconstrained sequence averaged over the year.

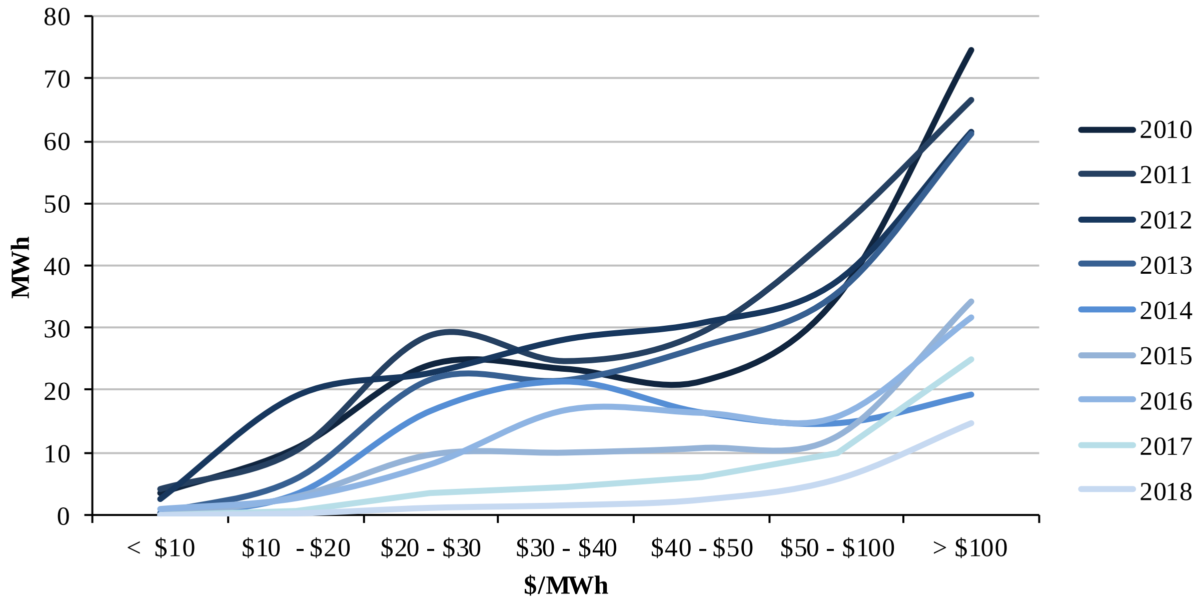
Figure 3-3: Average Hourly Output from PGS (MWh)



HOEP declined from an average of $36/MWh in 2010 to $22/MWh in 2018, so the Panel would expect some diminution in PGS output because there could be fewer hour pairs both when the high-price hour was above the fixed cost of operating PGS and meeting the price spread needed for PGS to profit from HIM. To account for this effect, a specific price threshold was analyzed, from a low price of $10/MWh to a high price of $100/MWh, far greater than the necessary 2:1 price spread. In recent years, the difference in output between average output during such low-price hours and high-price hours has been declining. For example, while average output at the PGS in low-price (under $10/MWh) hours has always been minimal, the average output during hours with a HOEP greater than $100/MWh has fallen from 75 MWh in 2010 to a low of 15 MWh in 2018 – an 80% decline, as shown in Figure 3-4.

OPG has suggested several reasons for the reduction of output at PGS other than the reduced effectiveness of the HIM. OPG states that one of the biggest determinants in reduced output at PGS is high water levels on Lake Erie. Higher water levels can reduce the ability to shift water via the PGS, as it hinders the ability to move more water through the Beck Stations after it has been pumped uphill to the PGS reservoir. The Panel recognizes that high water levels may hinder the use of PGS to some extent, but questions whether it has eliminated the time-shifting opportunities altogether.

Figure 3-4: PGS Average Hourly Output (MWh) Compared to HOEP



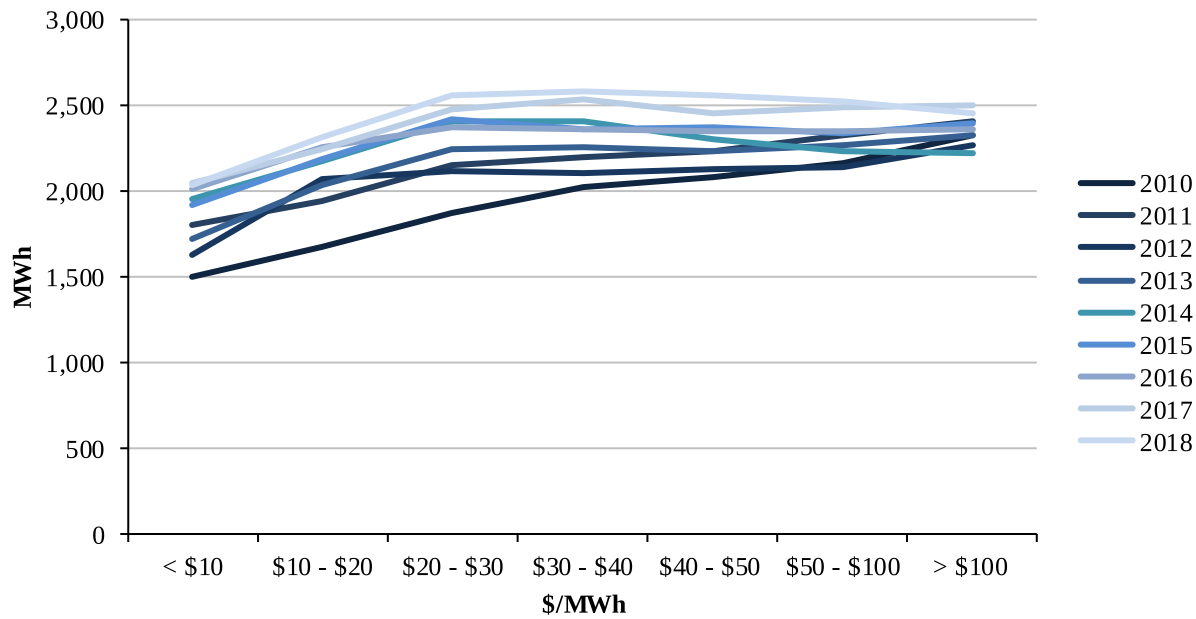
Prescribed Asset Time-Shifting Trends

The HIM initially applied to a subset of what are now the OPG prescribed hydroelectric assets, which included the Sir Adam Beck Generating Stations (Beck I, Beck II and PGS), the nearby Decew Generating Station and the RH Saunders Generating Station on the St. Lawrence river. The Panel therefore analyzed whether total output at these initial prescribed assets is being time-shifted to the same extent as it was when the HIM was first introduced.

While much of the capacity of the initial prescribed assets is considered baseload, these assets have some ability to shift output. Similar to the Beck complex, shifting output from low value to high value hours has declined over the past decade. The difference in output at OPG's initial prescribed assets (excluding PGS) when HOEP was greater than $100/MWh compared to when it was below $10/MWh was 830 MWh in 2010, but dropped almost in half to 426 MWh in 2018.

Figure 3-5 clearly shows the output curve based on HOEP becoming flatter in recent years.

Figure 3-5: Prescribed Average Hourly Output (MWh) Compared to HOEP



Again, OPG has presented a number of reasons why they have reduced time-shifting at the initial prescribed assets (excluding PGS) over this time period. First, they note that – similar to the PGS – the high water levels in recent years have reduced the ability to store water. Second, OPG notes an increase in regulatory and environmental requirements that has reduced how much OPG can raise and lower reservoirs (i.e., time-shift water). Third, the high prices (over $100/MWh) used in this analysis are much less common now than in 2010, limiting the number of opportunities for OPG to target those hours through time-shifting. The Panel accepts that those issues have had some effect, but has not been able to assess its extent and therefore cannot be sure that the sharing of HIM revenues has not contributed to the reduction.

Previously Non-Prescribed Assets Time-Shifting Trends

Between May 2009 and October 2014, 3,100 MW of OPG's hydroelectric fleet operated on a merchant basis. In 2014, the Province proposed to move these merchant assets to rate regulation, noting that OPG's unregulated hydroelectric generators were the "last significant generators" to be paid "entirely on HOEP". Rate regulation, according to the proposal, would "improve OPG's ability to properly plan for and maintain these important hydroelectric assets".[98] These assets were brought under rate regulation in 2014.

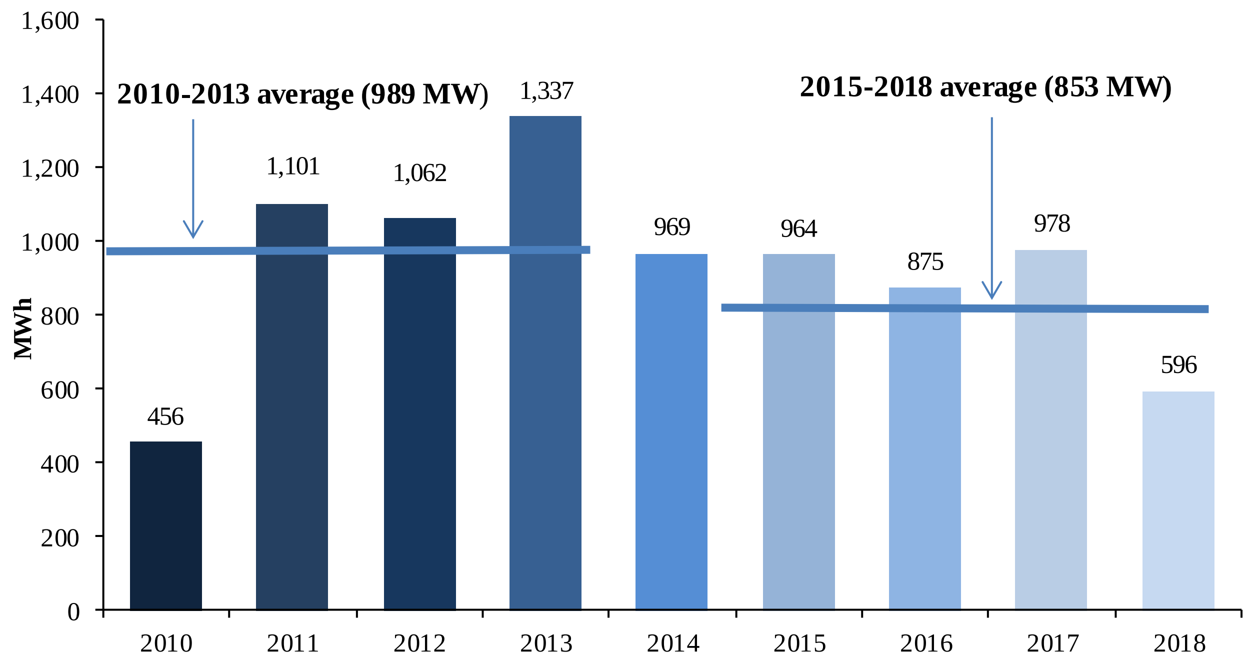
In each full year from 2010 through 2013, the previously unregulated assets operated on a merchant basis; in each full year from 2015 through 2018, they were rate-regulated and subject to the HIM. The Panel examined whether OPG shifted output more when it relied on the wholesale market price than when it was subject to rate regulation and the HIM. This provides a test of whether the HIM is as good as merchant generation in supporting economic efficiency via shifting output from low to high value hours.

OPG, on average, reduced the spread in output during low and high value hours at these assets. In the 2010-2013 period, the average spread was 989 MWh, or nearly 14% higher than the 853 MWh spread in the 2015-2018 period.

Figure 3-6 shows the decline in the average spread in output between high-priced and low-priced hours after the shift from merchant operation based on HOEP revenue alone and regulated rates combined with the revenue sharing applied to the HIM. While there is substantial variation in the annual output spread through 2013, particularly the low output in 2010, the decline between the average of the merchant years and the average of the regulated years suggests a dampening of the incentive to generate when the price is highest.

[98] Ministry of Energy, "Proposed Amendment to O. Reg. 53/05 (Payments under Section 78.1 of the Act), made under the Ontario Energy Board Act, 1998", Ontario's Regulatory Registry, posted September 13, 2013: https://www.ontariocanada.com/registry/view.do?postingId=14082&language=en

Figure 3-6: Spread in Output at Non-Prescribed Assets ($100/MWh vs $10/MWh HOEP)



As with the other asset analyses, there are competing explanations. OPG notes that the price curves have flattened over this time period, reducing the incentive to shift output. However, our analysis of output when HOEP exceeds $100/MWh compared to when it is below $10/MWh suggests that OPG is responding less to the high-price hours that still occur. OPG also notes that the high water levels of the last few years have reduced the opportunities to reduce output at many of their plants that are essentially run-of-the-river. Finally, OPG argues that increased environmental and safety regulations have reduced the amount of time-shifting that can be pursued by OPG. The Panel recognizes these factors, but cannot be certain that they alone account for the reduction in time-shifting.

3.1.8 Conclusions and Recommendation

The efficiency of the wholesale electricity market depends on participants having an incentive to offer their marginal or opportunity cost of energy. Given that OPG's rate-regulated hydroelectric fleet provides about 17% of Ontario's electricity and sets the market price in about 40% of all intervals, it is essential for the efficiency of the market that OPG's hydroelectric fleet have a simple and undiluted incentive to offer their marginal cost or opportunity cost. This creates an efficient offer stack and transmits accurate price signals to the rest of the market. It encourages OPG to store water to the extent practicable when prices are low and use that water to generate when prices are high, reducing price variability and saving money for consumers. However, rate regulation applied to OPGs hydroelectric assets essentially pays a fixed price per MWh generated, eliminating any incentive to offer at marginal cost or opportunity cost.

The HIM has the potential to fully replicate the incentive facing a merchant generator to offer their marginal cost. However, this incentive is diluted by sharing of the HIM revenues with consumers.

If OPG earns its forecasted HIM revenues, then any amount above this threshold is shared 50/50 with ratepayers, which, according to economic logic and OPG's previous filings in OEB proceedings, reduces its incentive to time-shift. This is because the cost of shifting – in the form of the cost of energy to pump water at PGS and operating costs elsewhere, combined with the risk that future prices are lower than current prices – is fully borne by OPG, while the benefit earned by time-shifting must be shared with ratepayers. This has the potential to reduce the instances in which OPG may choose to time-shift. When this sharing mechanism is in effect, the incentive for 40% of Ontario's price-setting assets to be offered efficiently into the market is diminished. While revenues have been well below this threshold in recent years, in the future revenues may be above the threshold. The HIM design should be appropriate for the full range of plausible future conditions.

Economic regulation, as it is practiced in Ontario, according to the OEB, acts as a "substitute for the economic forces that would normally influence [utilities] in a competitive market".[99] In this case, the revenue-sharing aspects of the HIM have the potential to reduce the efficiency of

[99] See the OEB's "Energy Sector Regulation – A Brief Overview": https://www.oeb.ca/oeb/_Documents/Documents/Energy_Sector_Regulation-Overview.pdf

the wholesale market, in which case the full value of efficiency gains – which may be greater than the financial gain to OPG – would not be passed on to consumers.

Recommendation 3-1

The Panel recommends that the OEB consider revisiting the sharing with consumers of net HIM revenue exceeding a threshold. The Panel further recommends that the OEB consider keeping the forecast used to determine the imputed HIM revenue in place for no less than three years, as has recently been the case.

The Panel has focussed this discussion on OPG and the HIM. However, other hydroelectric resources that have the ability to store water and are subject to contracted rates have little or no incentive to shift water from low-price to high-price hours. The Panel has not investigated other hydroelectric resources, but if there are significant storage capabilities, the efficiency of the market would benefit from applying a mechanism to create efficient incentives to store water.

3.2 Defining and Addressing the System Flexibility Need

3.2.1 Executive Summary

In 2016, the IESO identified a need for greater flexibility to address increased forecast uncertainty, while acknowledging that the continued use of out-of-market actions was not sustainable.

The IESO's solution is to procure a predetermined amount (200 MW) of additional Operational Reserve (OR) intended to schedule a generator(s) to come online that otherwise would not be committed and provide greater capacity than their scheduled amount – providing "spare energy" to address the need.

The solution lacks specific criteria for when it should be invoked. It relies largely on the discretion of the IESO to determine when spare energy is required, which leads to inconsistent market outcomes.

The solution also does not align with actual needs due to its “all or nothing” design. Regardless of the need for flexibility, the amount scheduled is uniformly 200 MW. If the solution does not produce the desired amount of spare energy, out-of-market actions – which it was explicitly intended to reduce – are used.

The current solution was intended to be temporary, but is now expected to remain in place beyond the Market Renewal Program (MRP), which is years from being completed.[100]

The IESO should re-consider its approach and develop a long-term, cost-effective solution.

3.2.2 Background: The Need for Flexibility

The Problem Identified and Justified

The IESO has established the need to address system flexibility, noting that the need is pursuant to its obligation to meet reliability standards relating to balancing supply and demand.[101,102]

[100] The IESO is currently reviewing the existing solution and may look to further evolve the program.

[101] See the IESO presentation, "Enabling System Flexibility: Stakeholder Engagement Presentation", dated June 24, 2016, Slide 47: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/esf/ESF-20160624-Presentation.pdf?la=en

[102] See NERC Reliability Standard BAL-001: “to maintain interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.”, available at: https://www.nerc.com/pa/Stand/Pages/BAL0011RI.aspx

In order to maintain the real-time balance of supply and demand, the IESO has several safeguards in place, as required by the North American Electric Reliability Corporation (NERC) and the North East Power Coordinating Council, Inc. (NPCC):[103]

- **Regulation service**: used for intra-interval fine tuning of supply and demand balancing on a second-by-second basis.
- **OR**: Capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.

Flexibility is defined by the IESO as the capability of the system to respond to intra-hour differences between expected supply/demand levels and actual production/consumption.[104] The IESO has noted that the grid is now less flexible due to changes in the supply mix (i.e. coal phase out), while the need for flexibility has increased due to the significant increase in variable generation.[105]

The IESO's 2016 Operability Assessment discussed how variable wind and solar generation forecasts remain unreliable until the hour ahead of real-time, resulting in significant scheduling uncertainty.[106] The impact of this uncertainty increases when there are large amounts of

[103] The flexibility requirement is above and beyond the requirements for regulation and contingency reserves as required by NERC and NPCC.

[104] See the IESO's updated definition of system flexibility from Market Manual 7.1, Page 9: http://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/system-operations/so-SystemsOperations.pdf?la=en

[105] IESO has 5,077 MW of wind (4,486 MW transmission connected, 591 MW embedded) and 2,583 MW solar (424 MW transmission connected, 2,159 MW embedded) capacity installed as of September 2019. For more information, see: www.ieso.ca

[106] See the IESO's 2016 Operability Assessment, page 3: http://www.ieso.ca/-/media/files/ieso/document-library/engage/esf/esf-20161208-2016-ieso-operability-assessment-summary.pdf?la=en

variable generation (i.e. wind or solar) forecasted.[107] Forecasting errors – either when generation is lower than forecast, or demand is greater than expected – can result in an increased need for supply.

What is Operating Reserve?

Operating Reserve (OR) is stand-by power or demand reduction that the IESO can call on with short notice to manage an unexpected mismatch between generation and consumption. OR may be activated by the IESO in response to: a sudden unexpected change in demand; a generation loss or the loss of transmission resulting in a more restrictive operating limit that reduces or completely removes access to available supply; or uncertainty associated with generators unable to follow their dispatch instructions.

There are three classes of OR, defined by the time required to bring the energy into use: 10-minute spinning OR (already synchronized to the grid), 10-minute non-spinning OR (not synchronized) and 30-minute OR (not synchronized). 10-minute OR must be at least equal to the largest contingency, typically 945 MW, and at least 25% of that amount must be 10-minute spinning OR. 30-minute OR must equal one-half of the second largest contingency, typically 473 MW.

When OR is dispatched to provide energy, reliability standards require ISOs to schedule additional OR to meet the standard and recover from any shortage within 105 minutes when the cause is the loss of generation ≥ 500 MW (all other events have 90 minutes to recover). ISOs are permitted to operate without sufficient 30R for up to 4 hours.

[107] Wind and solar forecast error impacts both the generation forecast and the demand forecast, as some generators are transmission connected generators, whereas others are embedded within distribution systems and are viewed as a net reduction in demand (as they are not directly connected to the grid as generators).

As forecasting errors became more pronounced with the large-scale introduction of variable generation, the IESO began considering ways to address the problem. In its 2016 Operability Assessment, the IESO recommended "enhancing the flexibility [ability to start within 30 minutes] of Ontario supply resources to ensure that there are increased quantities of resources able to address hour-ahead variable generation forecast inaccuracy, 95% of the time".[108]

The IESO initially calculated a targeted need of 1,000 MW of flexible capacity to manage forecasting error in 2018. This estimate was later revised to 740 MW of flexible capacity in light of several changes in assumptions, including the cancellation of plans to procure additional wind and solar capacity.[109]

Previous Method of Providing Flexibility

Prior to May 2018, the IESO relied exclusively on out-of-market actions to maintain reliability when faced with a lack of spare energy. The out-of-market control actions included:

- Pre-emptively reducing wind and solar forecasts in order to commit more flexible gas-fired units and/or schedule fewer net exports;
- Pre-emptively constraining on flexible resources out-of-merit order (usually the Lennox Generating Station) when forecasts of wind and solar output exceeded a certain threshold; and
- Curtailing exports mid-hour.

[108] The remaining 5% of the time, the IESO "would rely on the limited incremental flexibility provided by the hydroelectric fleet and utilize short-term flexibility on Ontario's interties where available". For more information, see the IESO's 2016 Operability Assessment, page 3: http://www.ieso.ca/-/media/files/ieso/document-library/engage/esf/esf-20161208-2016-ieso-operability-assessment-summary.pdf?la=en

[109] This assumption change included the cancellation of the second round of Large Renewable Procurement and the reduced Feed-in Tariff targets. The assessed flexibility need is intended to be revised periodically as system conditions change. The 740 MW estimate does not consider the renewable contract cancellations in summer 2018.

Typically, the IESO constrained on an additional resource, while also reducing the wind and solar forecasts. Both of these actions were intended to schedule additional gas resources so that their spare capacity could be brought online if needed. The IESO would usually select Lennox to be constrained on, a resource with four dual gas- and oil-fired generators with combined capacity of 2,200 MW. The IESO recognized these actions were non-transparent, potentially inefficient and inadequate for the future.

3.2.3 Interim Flexibility Solution Identified

Flexibility Procedure Formalized

The IESO initiated the Enabling System Flexibility Stakeholder Engagement (Stakeholder Engagement) in June 2016 to consider a temporary flexibility solution (Interim Flexibility Solution) to address the need for greater flexibility and reduce the number of out-of-market actions.[110] A long-term solution was initially expected to be developed as part of the MRP.

In this context, the IESO acknowledged that OR can be used for three purposes – contingency, regulation, and flexibility – and that 30-minute OR was most appropriate for addressing flexibility needs.[111]

The IESO proposed procuring spare energy by increasing the scheduled amount of 30-minute OR above what is otherwise required for contingencies on an “as needed” basis, as the required amount was not considered sufficient to cover the flexibility need. The intention of scheduling the additional 30-minute OR is to trigger generation to come online that has the capability to provide the desired flexible capacity. This is illustrated in Figure 3-7.[112]

[110] The IESO defines out-of-market actions as “when the system operator dispatches a resource even though it would not have cleared and been dispatched by the market.” For more information, see the Market Renewal Fact Sheet, “Out-of-Market Operator Actions”, page 1: http://www.ieso.ca/-/media/files/ieso/document-library/market-renewal/fact-sheet-10-out-of-market-operator-actions.pdf?la=en

[111] See the IESO’s presentation “Enabling System Flexibility – Meeting #5”, dated October 23, 2017, Slide 6: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/esf/esf-20171023-presentation.pdf?la=en

[112] Ibid. Slide 10.

Figure 3-7: An Illustration of a Flexibility Event

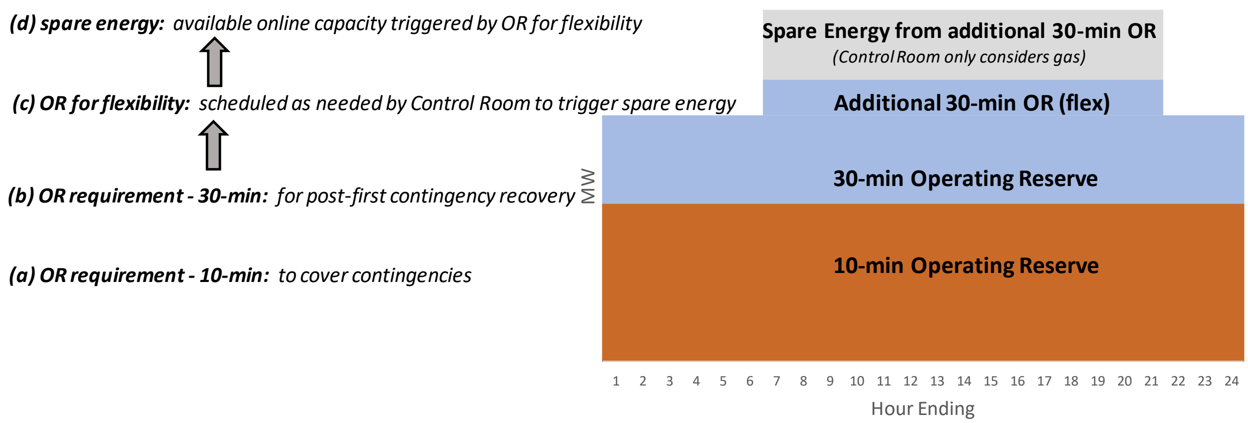


Figure 3-7 outlines four interrelated components:

a. **OR requirement – 10-minute:** the mandatory OR (10-minute) to cover contingencies.
b. **OR requirement – 30-minute:** the mandatory OR (30-minute) to position the system, post-first contingency, to be able to recover at least half of the needed 10-minute OR within 30-minutes.
c. **OR for flexibility – additional 30-minute OR:** if a flexibility need is identified by the IESO, the mechanism used to address the need is to schedule an additional 200 MW of 30-minute OR during the affected hours.
d. **Spare energy – triggered from additional 30-minute OR:** Although the 30-minute OR is increased to address the flexibility need, it is actually the spare energy associated with the 30-minute OR that is desired. The source of this spare energy is selected using an internal procedure that only qualifies gas-fired resources.

Flexibility Events and Flexible Resources

The IESO defines a "flexibility event" as an occasion when there is an increased risk of a "material" intra-hour difference between forecasted supply and demand, and actual conditions in future hours.[113] The IESO also defined the operating characteristics of flexible resources.[114] Although dispatchable loads and hydroelectric generators can provide 30-minute OR – and given the rules and their operating characteristics, can fulfill the stated flexibility requirements – the IESO does not consider these resources for flexibility given the complexities in determining their available spare energy. As a result, the IESO may end up taking additional out-of-market actions to address flexibility, when in fact non-gas resources may have been in a position to provide additional spare energy had they been considered in the IESO's calculation.

The IESO estimated that for 2018 there would be approximately 110 days in which the Interim Flexibility Solution would be needed and that the average hourly flexibility need could be addressed with less than 200 MW of 30-minute OR.[115] For simplicity, the IESO used this 200 MW figure as the standard fixed increase in the amount of 30-minute OR used in the Interim Flexibility Solution.

The Interim Flexibility Solution became operational in the beginning of May 2018.

[113] The IESO-Controlled Grid Operating Procedures outlines IESO actions to manage variable generation events. Three specific examples of flexibility events outlined in the procedures include conditions with the risk of: "material differences between forecasted and actual variable generation output, significant variable generation ramp events, or material differences between forecasted and actual Ontario demand." For more information, see the IESO-Controlled Grid Operating Procedures, Part 7.1, Section 2.4.2 System Flexibility Events, page 9: http://www.ieso.ca/en/sector-participants/market-operations/-/media/ccdae55168cc4ae8a4b73894ba305ebe.ashx

[114] The resource must be able to provide energy within 30 minutes of being called upon, including resources that can start within 30 minutes, as well as those that are already online and able to respond in 30 minutes. The IESO has outlined further operating characteristics for flexible resources: located in area where capacity not limited by transmission constraints, min. run-time of 2 hours or less, contribute for 2 sustained hours, start twice per day, min. turnaround time (de-sync to resync) of 3 hours, 90% availability rate, and a 95% starting reliability rate. For more information, see the IESO's presentation "Enabling System Flexibility – Meeting #3", dated January 27, 2017, slides 19, 21, 22, 23: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/esf/ESF-20170127-Presentation.pdf?la=en

[115] See the IESO's presentation "Enabling System Flexibility – Meeting #5", dated October 23, 2017, slide 16: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/esf/esf-20171023-presentation.pdf?la=en

3.2.4 Issues with Interim Flexibility Solution

The Interim Flexibility Solution continues to be used without specific criteria, it is not scalable, it is not consistently effective and no analysis has been completed to ensure it is the lowest cost solution. The following sections discuss these issues in greater detail.

Unclear Criteria for Triggering Solution

There is a lack of clarity on issues that have significant implications for the quantity of flexibility that the IESO seeks to add, and what conditions trigger such a need.

The IESO may ultimately procure spare energy whenever desired – even when it may not be necessary – because the Interim Flexibility Solution is not specific as to what conditions are required for it to be used. In fact, in its market rule amendment, the IESO left open the option to increase the 30-minute OR by any amount, for any length of time.

The IESO's procedure for assessing when additional 30-minute OR should be scheduled directs the IESO to consider the amount of spare energy available against the operability risk, which includes demand and variable generation uncertainty and ramping needs. Although the procedure does list conditions that may contribute to the need for additional flexibility, the list concludes with a note stating that it is not exhaustive and ultimately, it is left to the discretion of the IESO to use their knowledge and experience to assess whether the anticipated conditions present a need for additional flexibility in real-time.

The need for greater clarity on what the IESO considers a "material" divergence between forecast and actual conditions sufficient to warrant initiating the Interim Flexibility Solution was also raised by a Market Participant during the stakeholder engagement in 2017. The Market Participant requested that the IESO "consider publishing a minimum MW quantity that constitutes ‘material differences’” as it relates to forecasted and actual demand in the Market Manual.[116] The IESO has not acted on this request.

The lack of clarity in defining the circumstances that justify intervention appears to have resulted in a greater-than-anticipated usage of the Interim Flexibility Solution. The IESO initially estimated 110 days of need with an average event length of five hours. However, the data from the first year when the Interim Flexibility Solution was in place shows that the IESO scheduled additional 30-minute OR on more than 180 days for an average of 12 hours per event.[117] Nearly half of the time the IESO used the solution, it acted more than eight hours ahead of real-time – far sooner than would appear prudent, considering the IESO’s 2016 Operability Assessment indicated that variable generation forecasts remain unreliable until the hour ahead of real-time.[118] In summary, the IESO has exceeded its initial estimates and used the solution in more than a quarter of all hours throughout the first year of implementation.

One reason for the higher than anticipated usage of the Interim Flexibility Solution may arise from instances unrelated to variable generation forecast error. For example, an additional 200 MW of 30-minute OR was scheduled for two days in June 2019 (June 18 and 19) when there was a low wind forecast (less than 500 MW), low demand forecast (less than 18,000 MW) and typical seasonal temperatures. Notwithstanding, the flexibility event was scheduled for 15 and 16 hours, respectively, as the IESO determined there were no spare resources online and no gas units committed.[119]

[116] See the OPG letter dated December 21, 2017 relating to the IESO’s Enabling System Flexibility presentation: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/esf/esf-20171222-opg.pdf?la=en

[117] Based on data from Control Room Operator logs.

[118] The IESO informed the Panel that such actions are taken in advance of real-time as some of the resources that may need to be committed require more than a few hours of start-up time.

[119] Control Room Operator logs, June 18, 2019 and June 19, 2019.

In the first year of the flexibility solution being implemented, the Panel observed that there was not a reduction in the number of hours that out-of-market actions were taken to address flexibility.[120] These out-of-market actions were taken in addition to using the flexibility mechanism more than 2,400 hours (more than a quarter of all hours). If in fact the Interim Flexibility Solution is warranted to be used with such frequency, a more direct approach to the underlying issue of redundancy should be considered. The IESO should also establish more definitive criteria for the need for additional flexibility, as the option to Control Room Operators of using "their knowledge and experience to assess whether the anticipated conditions present a need for additional flexibility in real-time" creates a very low bar for the flexibility solution to be triggered, rendering any preceding criteria moot.

Design is Not Scalable or Consistently Effective

The Interim Flexibility Solution sends an indirect market signal of the need for spare energy. Procuring an additional, pre-determined 200 MW of OR capacity does not reflect the specific need for spare energy. Since the design is not scalable, the desired product cannot be efficiently priced and acquired.

As noted previously, the IESO stated that the "near-term flexible capability required is **up to** 740 MW".[121] When introducing the solution in October 2017, the IESO stated that scheduling an additional 200 MW of 30-minute OR would provide the desired flexibility and that this flexibility would typically only be required for five hours.[122] The IESO's procedure states that it

[120] Based on analysis comparing the number of hours that Lennox was constrained on in the year prior to the solution being implemented, to the number of hours Lennox was constrained on following the implementation of the solution.

[121] See the IESO's presentation "Enabling System Flexibility – Meeting #4", dated August 1, 2017, Slide 24: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/esf/ESF-20170801-Presentation.pdf?la=en

[122] See the IESO's presentation "Enabling System Flexibility – Meeting #5", dated October 23, 2017, Slide 16: http://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/esf/esf-20171023-presentation.pdf?la=en

should procure the additional 200 MW of reserve capacity for a minimum of four hours, based on the technical requirements of non-quick start units as opposed to having any reference to addressing the flexibility need.[123] As such, the IESO designed its Interim Flexibility Solution to meet the upper limit of need and has no provision to reduce or increase the amount procured if the need is lower or higher.

For example, if the need for spare energy need is 50 MW for two hours, the Interim Flexibility Solution calls for an increase in the scheduled 30-minute OR by 200 MW for at least four hours and could procure up to 740 MW of spare energy.

The Interim Flexibility Solution is also not consistently effective. If it “does not result in additional flexibility in the subsequent pre-dispatch runs”, the IESO’s procedure states the control actions that the IESO may utilize. Essentially, if additional 30-minute OR fails to provide spare energy (i.e. flexibility), the IESO reverts back to the previous method of out-of-market actions.[124]

Furthermore, out-of-market actions continue despite the high usage of the Interim Flexibility Solution. In the year following implementation of the Interim Flexibility Solution, the number of hours when Lennox was constrained on for flexibility increased by at least 10%.[125] Consideration should be given to reducing out-of-market actions by more directly addressing the need for flexibility.

[123] A minimum of four hours was established based on the average Minimum Generation Block Run-Time (MGBRT) for non-quick start units. MGBRT means the number of hours, specified by the Market Participant, that a generation facility must be operating at or above minimum loading point.

[124] The additional control actions are: manually override the wind or demand forecasts to improve the accuracy of pre-dispatch scheduling; constrain on dispatchable resources on a best effort economic basis; implementing Generation Shift Factor for total/regional wind output to minimize the ramp magnitude impact by max/min constraining wind resource, and curtailing export transactions, only as a last resort.

[125] This analysis was based on IESO data and only considered instances where Lennox units were manually constrained on to their minimum loading point and where comments were provided by the IESO suggesting the purpose of the constraint was for flexibility, with ambiguous or blank comments omitted. This data set was cross-checked with Control Room Operator logs.

Finally, no analysis has been presented by the IESO to show that the interim solution leads to lowest system costs in fully addressing the flexibility need, including the out-of-market actions taken to account for the inconsistent effectiveness.

The IESO should more clearly define, quantify and address the flexibility need more directly through a market-based approach.

Recommendation 3-2:

In order to provide more consistent market outcomes, the IESO should give further consideration to improving how the need for additional system flexibility is addressed, such as specifying the conditions that require intervention and scheduling the required amount of spinning reserve explicitly in the normal OR market. Although it is acknowledged that no industry standard exists to address flexibility, alternative solutions should also be considered to ensure the most suitable approach is used.

Appendix A: Market Outcomes for the Winter 2017/18 Period

This Appendix reports on outcomes in the IESO-Administered Markets for the Winter 2017/18 Period (November 1, 2017 to April 30, 2018), with comparisons to previous reporting periods as appropriate.

A.1 Pricing

This section summarizes pricing in the IESO-Administered Markets, including the Hourly Ontario Energy Price (HOEP), the effective price (including the Global Adjustment (GA) and uplift charges), Operating Reserve (OR) prices and Transmission Rights (TR) auction prices.

Table A-1: Average Effective Price by Consumer Class and Period ($/MWh)

Customer Class	Average Weighted HOEP ($/MWh)	Average Global Adjustment ($/MWh)	Average Uplift ($/MWh)	Effective Price ($/MWh)
Class A – Winter 2017/18	19.23	47.52	2.89	69.65
Class A – Summer 2017	10.13	54.27	2.38	66.78
Class A – Winter 2016/17	17.17	45.96	2.41	65.55
Class B – Winter 2017/18	23.11	87.51	3.15	113.77
Class B – Summer 2017	12.72	110.17	2.77	125.66
Class B – Winter 2016/17	20.14	90.01	2.66	112.81
All Consumers – Winter 2017/18	*N/A*	*N/A*	*N/A*	101.79
All Consumers – Summer 2017	*N/A*	*N/A*	*N/A*	110.31
All Consumers – Winter 2016/17	*N/A*	*N/A*	*N/A*	103.26

Table A-1 summarizes the average effective energy price in dollars per MWh by consumer class for the Winter 2017/18 Period (November 1, 2017 to April 30, 2018), the Summer 2017 Period (May 1, 2017 to October 31, 2017) and the Winter 2016/17 Period (November 1, 2016 to April 30, 2017).

The effective price is the sum of the HOEP, the GA and the uplift charges paid by a given class of consumers (whose nominal sum equals total system cost), divided by the total quantity of energy consumed.[126] Accordingly, it captures the hourly market price, payments under IESO reliability and other programs, prices payable for contracted and regulated generation and the costs of conservation and DR programs. It does not include all charges that appear on electricity bills, such as charges for transmission and distribution. Results are reported for three consumer groups: “Class A consumers”, “Class B consumers” and “All Consumers”.[127] The “All Consumers” group in Table A-1 represents what the effective electricity price would have been for all consumers if they all paid GA on a volumetric basis.[128]

Starting with Monitoring Report 29 (May 2016-Oct 2016) published in March 2018, the Panel moved embedded Class A consumers from the Class B consumer group to the Class A consumer group for the purposes of its reporting, including Table A-1.[129]

The Class B effective price remained significantly higher than the Class A effective price in the Winter 2017/18 Period. The Class A effective price increased by $4.10/MWh to $69.65/MWh,

[126] The average HOEP reported for each class is an average of the HOEP values in the reporting period weighted by that class’s consumption during each hour in the period. It was assumed that embedded Class A follows the same load profile as directly-connected Class A consumers.

[127] Consumers are divided into two groups: Class A, being consumers with an average monthly peak demand less than 5 MW but greater than 1 MW (or 500 kW for some sectors) that have opted into the class as well as consumers with an average monthly peak demand greater than 5 MW that have not opted out of the class, and Class B, being all other consumers. For more information, see Ontario Regulation 429/04 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998*: http://www.ontario.ca/laws/regulation/040429

[128] Since January 2011, the GA payable by Class A consumers has been based on the ratio of their electricity consumption during the five peak hours in a year relative to total consumption by all consumers in each of those hours. To the extent that Class A consumers reduce their demand during those hours, their share of GA is reduced. The remaining GA is allocated on a monthly basis to Class B consumers based on their total consumption in that month. For more information on the GA allocation methodology and its effect on each consumer class, see the Panel’s Industrial Conservation Initiative Report published December 2018, pages 4-12: https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

[129] Following past practice, the Panel assumes that embedded Class A consumers have the same average load profile as directly-connected Class A consumers. Given the change in the Panel’s definition of consumer groups (from “Direct Class A” to all “Class A” and from “Class B & Embedded Class A” to just “Class B”), there is no direct comparison to be made between effective prices reported in this report and those from reports issued before the Panel’s Monitoring Report 29 (May 2016-Oct 2016) published March 2018.

and the Class B effective price increased slightly – by $0.96/MWh to $113.77/MWh. The increase in the average effective price for Class A was modestly above the average growth rate in the Class A effective price over the last 5 years, which was just above $2/MWh per year. The increase in the average effective price for Class B was much less than the average growth rate in Class B effective prices over the last 5 years, which was just above $7/MWh per year. However, the Class B effective price has remained relatively constant in the last two winter reporting periods (while continuing to grow in the summer periods), and is down slightly from a price of $114.37/MWh in the Winter 2015/16 Period.

In July 2017, the minimum capacity required to qualify as a Class A consumer was lowered, causing a large increase in Class A demand and Class A system cost, as well as a large decrease in Class B demand and system cost. This increase in costs borne by Class A due to its increased size outweighed the increase in energy consumed by Class A, causing the Class A effective price to increase. The increase in HOEP paid by Class B consumers caused by the increase in overall demand outweighed the decrease in GA charges paid by Class B consumers due to the decrease in the number of members of Class B. This caused the Class B effective price for energy to increase as well.

A surprising result is that while both Class A and B effective prices rose in the Winter 2017/18 Period compared to the previous winter period, the effective electricity price tabulated for all consumers fell from $103.26/MWh in the Winter 2016/17 Period to $101.79/MWh in the Winter 2017/18 Period. This occurred because the overall increase in energy demand between the Winter 2016/17 and 2017/18 Periods was driven by the increase in Class A participants, who have a much lower effective cost than Class B. As a result, the percentage increase in total demand between the Winter 2016/17 and 2017/18 Periods was larger than the percentage increase in total costs, lowering the effective price for all consumers.

Figure A-1: Monthly Average Effective Electricity Price & System Cost

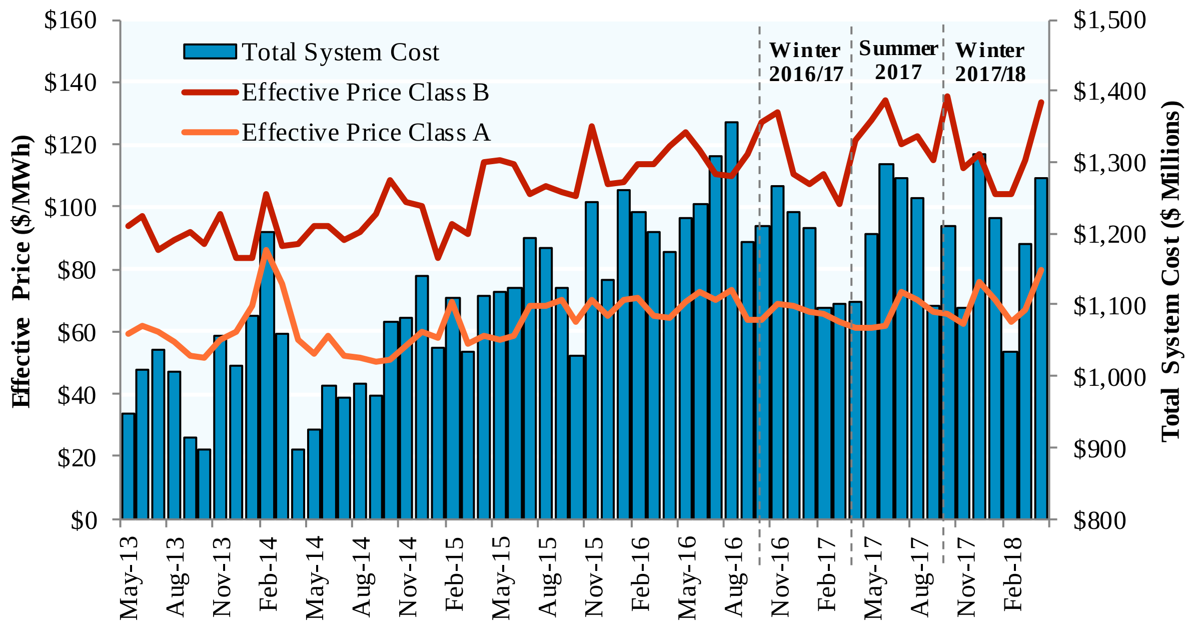


Figure A-1 plots the monthly average effective price per MWh for Class A and Class B consumers, as well as the total monthly system cost for the previous five years.

Total system costs borne by Ontario consumers in the Winter 2017/18 Period rose 1.7% compared to the Winter 2016/17 Period, but fell 2.9% from the Summer 2017 Period. This rate of increase across winter reporting periods is slower than average: over the last 5 years, total system costs have grown by about 5% per year. This slow rate of increase is also despite the increase in demand compared to the Winter 2016/17 Period, which contributed to the total cost of energy per MWh consumed decreasing in the Winter 2017/18 Period compared to the Winter 2016/17 Period.

Figure A-2: Average Effective Price for Class A Consumers by Component

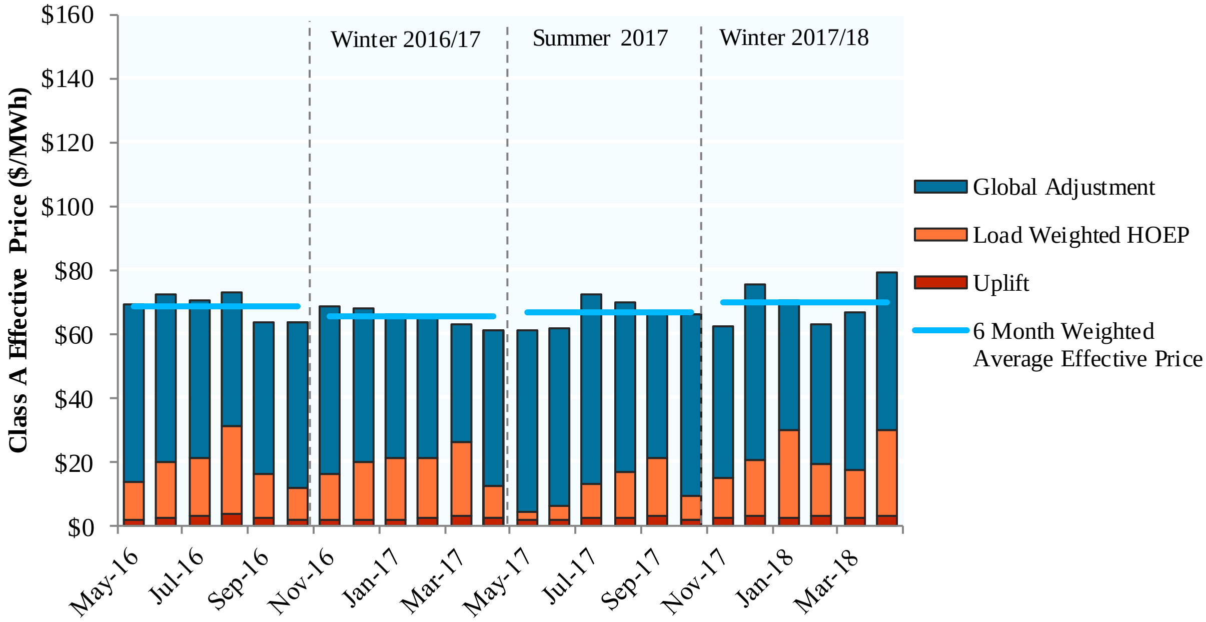


Figure A-2 separates the monthly average effective price into its three components (average load weighted HOEP, average GA and average uplift charges) for Class A consumers for the previous two years. They also show the total effective price averaged over each six-month period for each consumer class.[130]

Class A and B effective prices in the Winter 2017/18 Period followed a similar trend to one another: both increased slightly in December 2017, dropped in the new year, and rose sharply in April 2018. In March 2018, the OEB issued a Payment Amounts Order further to a proceeding on OPG's Application to set payment amounts for its rate regulated hydroelectric

[130] The GA is primarily composed of payments to rate-regulated and contracted generators to make up for the difference between the actual market revenues received by these generators (which are dependent on the HOEP, and thus are dependent on demand), and their contracted rates or, in the case of OPG, their regulated rates as set by the OEB. The GA also includes costs associated with various IESO conservation programs. For more information regarding the GA, see the IESO's webpage "Guide to Wholesale Electricity Charges": http://www.ieso.ca/sector-participants/settlements/guide-to-wholesale-electricity-charges

and nuclear facilities for 2017 to 2021.[131] The increase in payment amounts, which had an effective date of June 1, 2017, in conjunction with the increase in energy prices in April 2018 likely contributed to the increase in total costs and effective prices observed in April 2018. The flatter average slope of the effective price curve for Class B consumers over the last 3 reporting periods compared to the last 5-year period implies that the growth in Class B effective prices has slowed.

Figure A-3: Average Effective Price for Class B Consumers by Component

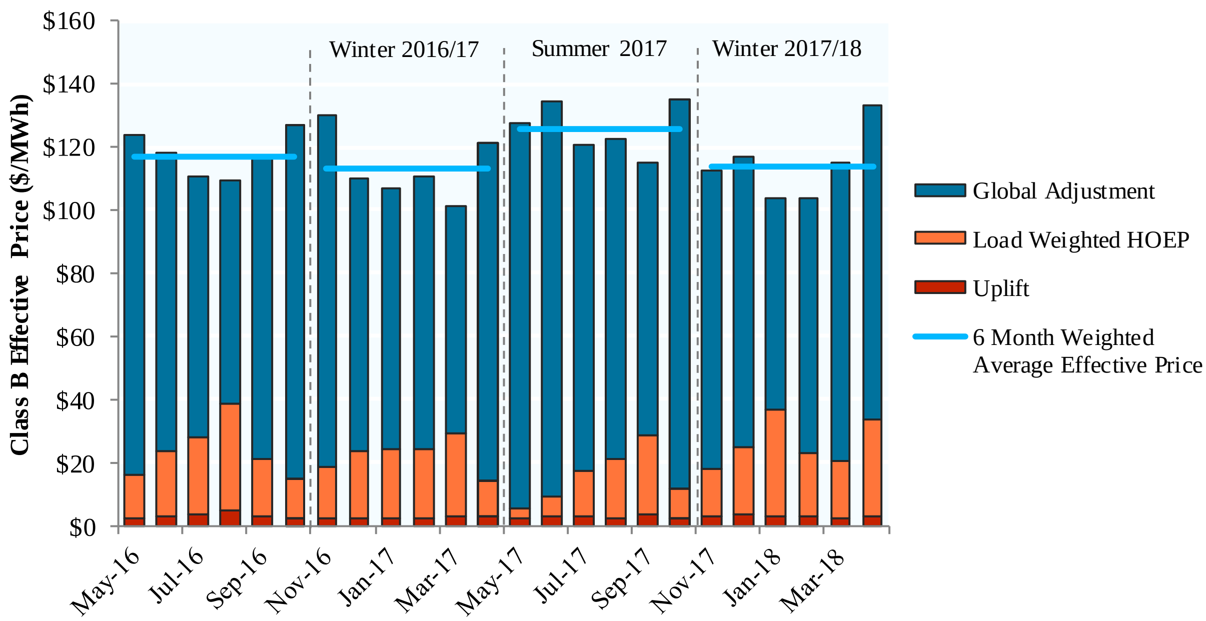


Figure A-3 separates the monthly average effective price into its three components (average load weighted HOEP, average GA and average uplift charges) for Class B consumers for the previous two years. They also show the total effective price averaged over each six-month period for each consumer class.

The GA is the guaranteed revenue less HOEP and uplift payments. The GA and the HOEP have an inverse relationship: when the HOEP decreases, the GA increases, but this is not

[131] See the OEB Payment Amounts Order dated March 29, 2018 (EB-2016-0152): https://www.oeb.ca/industry/applications-oeb/opg-payment-amounts-prescribed-generation-facilities

necessarily a one-for-one relationship. A higher GA tends to increase the effective price more for Class B than Class A consumers because the current GA allocation methodology has the effect of allocating to Class A consumers a lower share of GA per MWh consumed than Class B consumers pay.

On average, Class A prices continued to be higher during months when the HOEP was high, and Class B prices continued to be higher during months when the GA was high. April 2018 was a particularly expensive month for both Class A and B: The Class A price rose to $79.56/MWh, and the Class B effective price rose to $133.78/MWh. The effective GA and HOEP in April 2018 were also above average relative to the other months in the Winter 2017/18 Period for both Class A and B.

As explained previously in this section, the new payment amounts set for OPG's rate-regulated facilities likely contributed to this outcome, in conjunction with the increase in energy prices. Figure A-2 and Figure A-3 show how such a change can affect the GA for both classes of consumers without affecting the HOEP.

The Winter 2017/18 Period saw a modest increase in the six-month average HOEP compared to the Winter 2016/17 Period, rising from $18.18/MWh in the Winter 2016/17 Period to $20.95/MWh in the Winter 2017/18 Period. This increase was driven largely by high monthly average HOEP in January and April 2018. High energy prices in January were primarily driven by high natural gas prices: the average price of natural gas was $4.96/MMBtu (about 29% higher than the average natural gas price in the Winter 2017/18 Period), and gas-fired facilities set the real-time MCP during about 48% of all hours in January 2018 (see Figure A-7). High energy prices in April were driven by above average demand due to colder weather, and frequent shortfalls in wind generation throughout the month.

Figure A-4: Monthly & 6 Month (Simple) Average HOEP

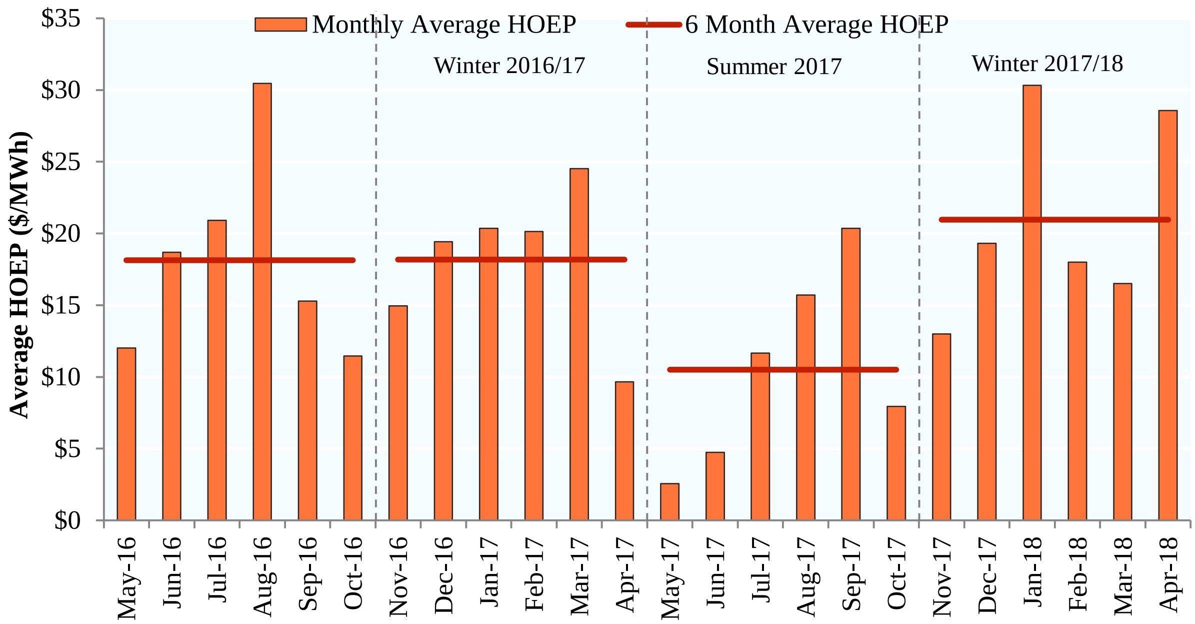


Figure A-4 displays the monthly average HOEP unweighted by the volume of energy consumed in any given interval (the "simple HOEP"), for each month between May 2016 and April 2018. Figure A-4 also displays the simple monthly average HOEP for each six-month period since May 2016. The HOEP is the unweighted average of the twelve MCPs set every five minutes within an hour.

The average gas price during on-peak hours was $3.87/MMBtu in the Winter 2017/18 Period and $3.78/MMBtu in the Summer 2017 Period, compared to $4.31/MMBtu in the Winter 2016/17 Period and $3.43/MMBtu in the Summer 2016 Period.

A correlation coefficient of 0.55 was observed between natural gas prices and the HOEP during the Winter 2017/18 Period, which is higher than that observed in both the winter and summer reporting periods over the last 2 years. This is likely because gas-fired facilities set the MCP during peak hours more frequently during the Winter 2017/18 Period than in the other periods.

Figure A-5: Natural Gas Price & HOEP during Peak Hours

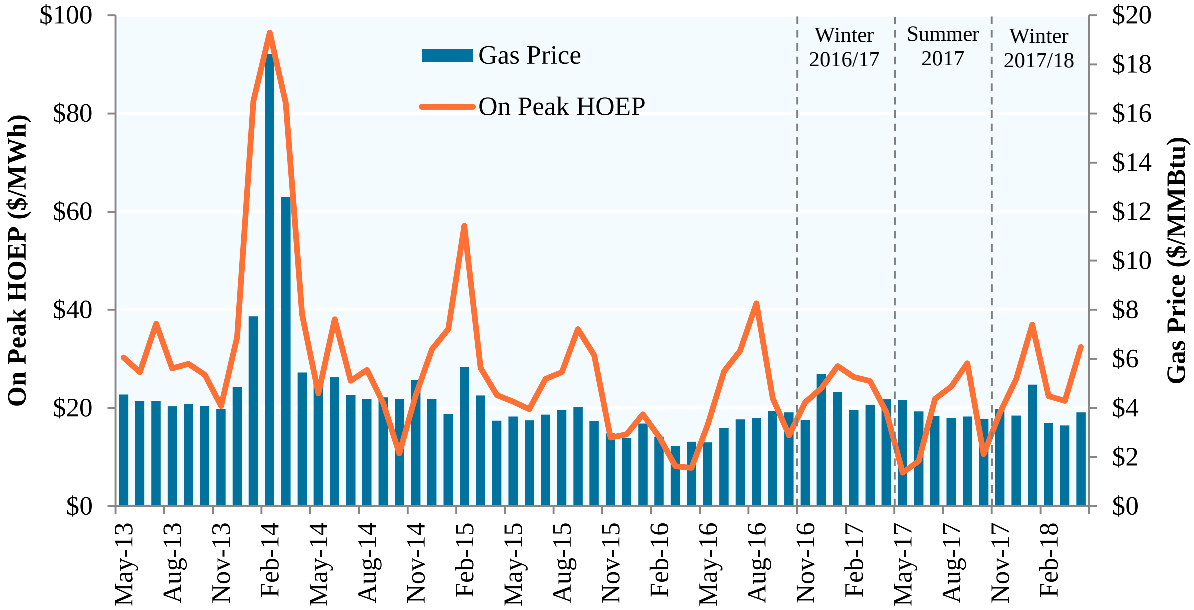


Figure A-5 plots the average monthly HOEP during on-peak hours and the monthly average of Dawn Hub day-ahead natural gas prices for days with on-peak hours for the previous five years.[132] Natural gas prices are compared to the HOEP for on-peak hours as gas-fired facilities frequently set the price during these hours. Gas-fired facilities typically purchase gas day-ahead.

In previous MSP reports, the Panel has noted that the addition of renewable energy to the grid (primarily wind) has reduced the frequency of hours that natural gas set the MCP in Ontario, weakening the correlation between the HOEP and natural gas prices relative to previous years. However, several other factors also affect the correlation between the HOEP and natural gas prices, including temperature and gas price volatility. Large changes in factors that affect the HOEP and natural gas prices individually (the HOEP is affected by demand, the frequency of outages, etc., whereas natural gas prices are affected by the relative scarcity of natural gas and costs faced by the natural gas producers) can weaken this correlation as well.

[132] On-peak hours here are defined as 7:00 AM to 11:00 PM, Monday to Friday (excluding holidays) to capture all hours when gas generators are likely to be running. Off-peak hours are all other hours.

The correlation between the HOEP and natural gas prices in the Winter 2017/18 Period suggests that natural gas prices can still substantially affect the HOEP, particularly when gas-fired facilities more frequently set the real-time MCP (see Figure A-7).

Figure A-6: Frequency Distribution of HOEP

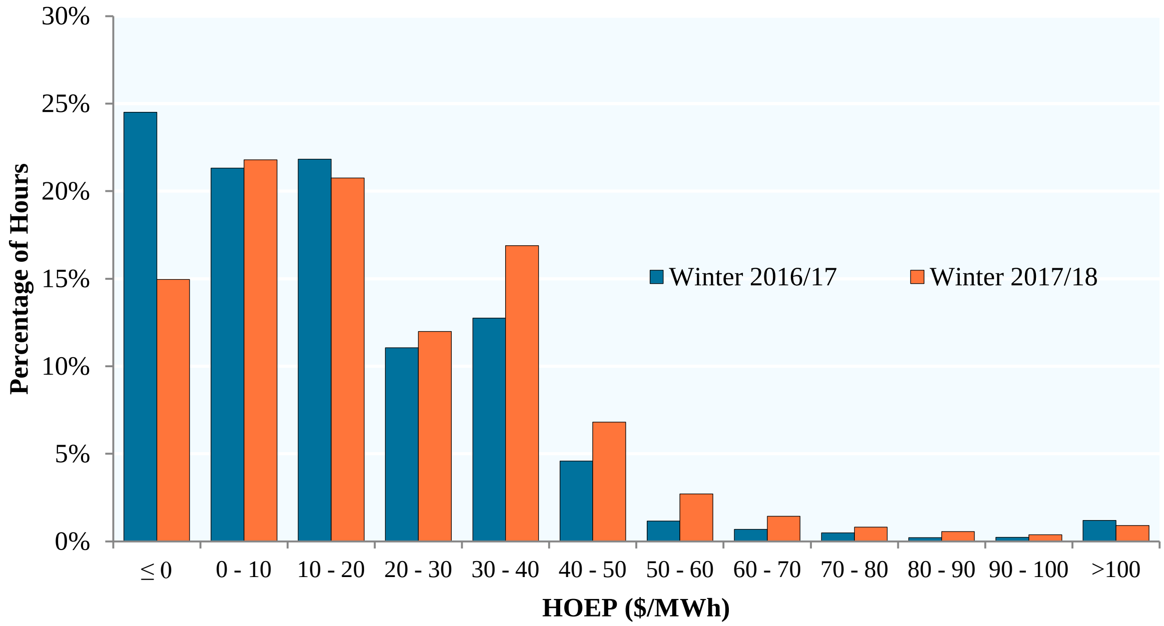


Figure A-6 compares the frequency distribution of the HOEP as a percentage of total hours for the Winter 2017/18 and Winter 2016/17 Periods. The HOEP is grouped in increments of $10/MWh, except for all negative priced hours which are grouped together with all $0/MWh values.

The Winter 2017/18 Period saw a decrease in negative HOEPs, and an increase in high-priced hours. Only 15% of hours in the Winter 2017/18 Period had a negative HOEP, compared to 25% in the Winter 2016/17 Period, while 42.5% of hours had HOEPs greater than or equal to $20/MWh in the Winter 2017/18 Period, up from 32.3% in the Winter 2016/17 Period. This is likely because demand was higher on average in the Winter 2017/18 Period than it was in the Winter 2016/17 Period, causing MCPs to be higher on average.

Figure A-7: Share of Resource Type Setting the Real-Time MCP

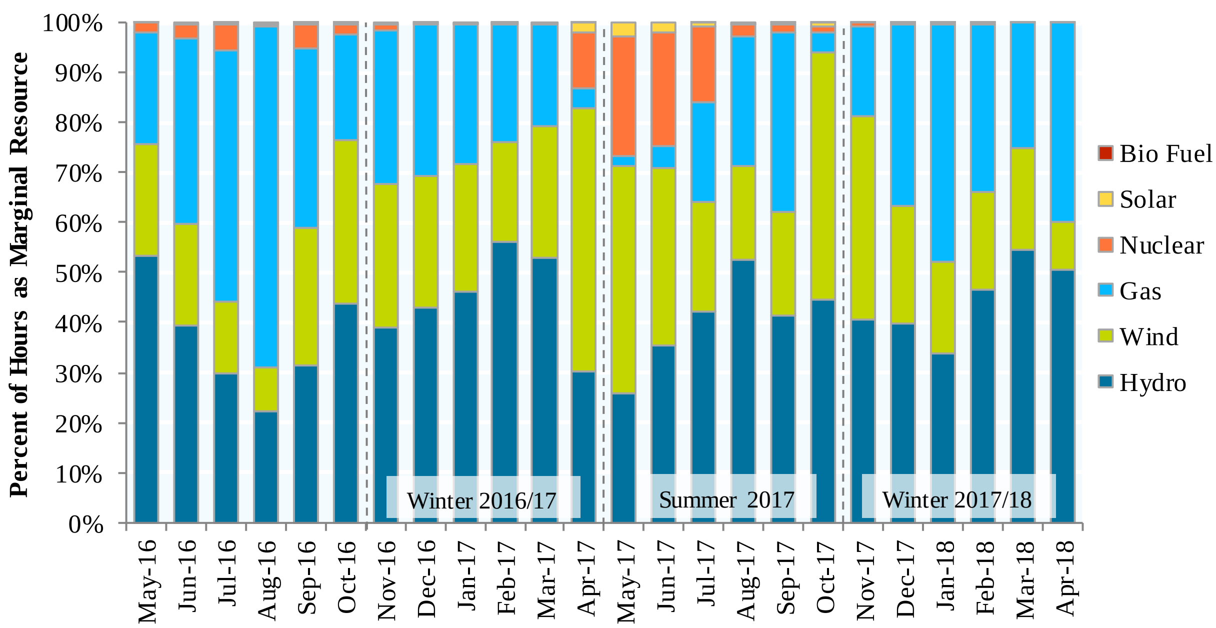


Figure A-7 presents the share of intervals in which each resource type set the real-time MCP in each month of the previous two years. The relative frequency of each resource type setting the real-time MCP is useful in understanding trends in the real-time MCP.

The ratio of hours that gas-fired facilities set the real-time MCP increased from 23% in the Winter 2016/17 Period to 33% in the Winter 2017/18 Period, while the ratio of hours that wind and nuclear resources set the real-time MCP decreased from 30% to 22% and from 2% to 0.1%, respectively. This outcome likely occurred because demand was higher in the Winter 2017/18 Period than in the Winter 2016/17 Period, resulting in higher energy market prices and thus the more frequent use of natural gas as a resource to meet peak demand. Hydroelectric resources set the real-time MCP during 44% of intervals in the Winter 2017/18 Period – continuing the trend of setting the real-time MCP more frequently than any other resource.

The frequency with which imports and exports set the one-hour ahead pre-dispatch (PD-1) MCP is important, as these transactions are unable to set the real-time MCP.[133] When the price is set by an import or export in pre-dispatch, a divergence between the pre-dispatch and the real-time MCP is more likely to occur.

Figure A-8: Share of Resource Type Setting the One-Hour Ahead Pre-Dispatch MCP

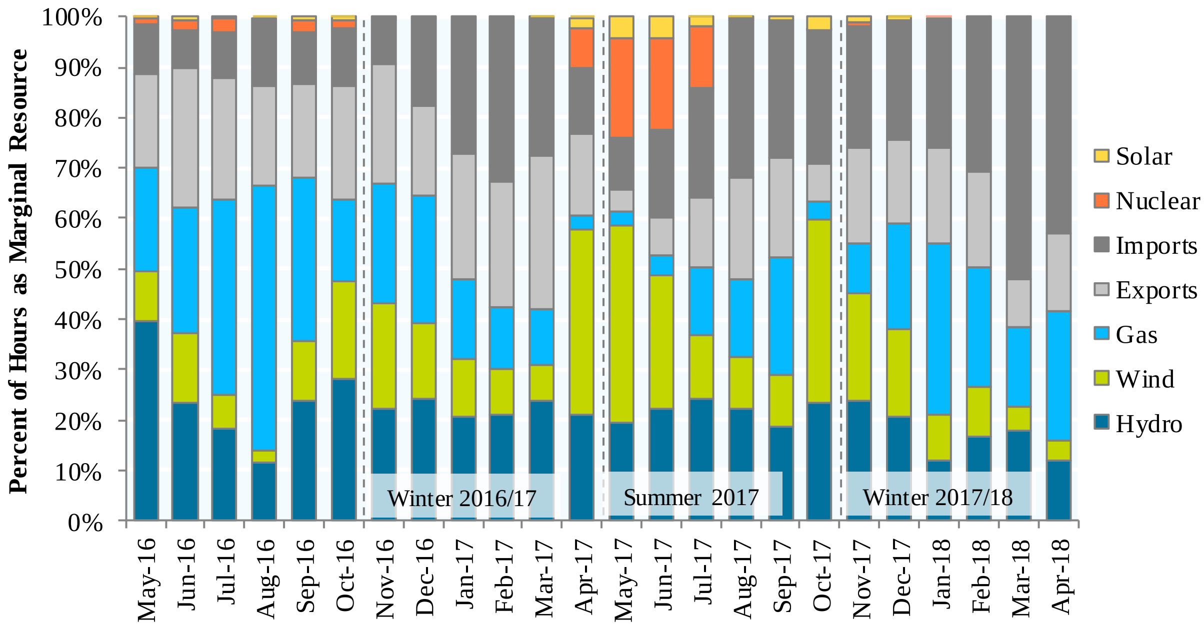


Figure A-8 presents the share of hours in which each resource type set the PD-1 MCP in each month of the previous two years. When compared with Figure A-7, Figure A-8 shows how the marginal resource mix changes from pre-dispatch to real-time.

The mix of resources setting the PD-1 MCP in the Winter 2017/18 Period saw an increase in natural gas, and decreases in wind, nuclear and hydro. The frequency of imports and exports

[133] Due to scheduling protocols, imports and exports are scheduled hour-ahead. In real-time, imports and exports are fixed for any given hour and their offer and bid prices adjusted to -$2,000/MWh and $2,000/MWh, respectively. Accordingly, imports and exports are treated as non-dispatchable in real-time and scheduled to flow for the entire hour regardless of the price, though their schedules may be curtailed within an hour to maintain reliability.

setting the PD-1 MCP also increased. The proportion of intervals that imports set the PD-1 MCP has grown sharply since the Winter 2015/16 Period, rising from 8% to 21% in the Winter 2016/17 Period, and to 33% in the Winter 2017/18 Period. This was caused in part by the Electricity Trade Agreement between the IESO and Hydro-Québec Energy Marketing, which came into effect in January 2017. The agreement requires that Hydro-Québec Energy Marketing submit import offers to the market using offer prices and quantities specified in the agreement. Those offer prices are determined using a formula that aims to undercut natural gas-fired generation by considering the costs that natural gas-fired generators are likely to incorporate into their offers. This results in Québec imports setting the PD-1 MCP more frequently during periods that natural gas resources set the PD-1 MCP often. The volume of imports from Québec also increased during the Winter 2017/18 Period relative to the Winter 2016/17 Period, creating more opportunities for importers to set the PD-1 MCP. The proportion of intervals that exports set the PD-1 MCP fell from 23% in the Winter 2016/17 Period to 16% in the Winter 2017/18 Period.

Gas resources set the PD-1 MCP in 22% of hours in the Winter 2017/18 Period, compared to 15% in the Winter 2016/17 Period. The increase in the frequency of natural gas resources setting the PD-1 MCP in the Winter 2017/18 Period compared to the Winter 2016/17 Period was caused by the expectation that demand would be higher in the Winter 2017/18 Period, resulting in the scheduling of more expensive marginal resources. Wind and nuclear resources saw reductions from 17% and 1.4% of hours in the Winter 2016/17 Period to 11% and 0.1% of hours in the Winter 2017/18 Period. Hydro saw a reduction from 22% of hours in the Winter 2016/17 Period to 17% of hours in the Winter 2017/18 Period.

The PD-1 MCP determines the schedules for import and export transactions for real-time delivery. While intertie transactions are scheduled on the basis of the PD-1 MCP, they are settled on the basis of the HOEP. To the degree that supply and demand conditions change from PD-1 to real-time, imports or exports may be over- or under-scheduled relative to the HOEP.

In the Winter 2017/18 Period there was a variation of less than $10/MWh between PD-1 and real-time prices for 69% of hours, the same percentage as in the Winter 2016/17 Period. The average absolute deviation between PD-1 and real-time prices in the Winter 2017/18 Period of $10.85/MWh was also very similar to the Winter 2016/17 Period average deviation of $11.16/MWh. January 2018 had an average absolute deviation between PD-1 and real-time MCPs of $20.71/MWh, which is the highest this value has been for any month over the last 3 reporting periods. These large deviations between PD-1 and Real-Time prices were primarily driven by the overestimation of demand and the underestimation of energy to be produced by variable generation in real-time, causing PD-1 prices to largely exceed real-time prices throughout January 2018.

Real-time prices diverge from PD-1 prices as a result of changing conditions from pre-dispatch to real-time.[134] Identifying the factors that lead to deviations between the PD-1 MCP and the HOEP provides insight into the root causes of the price risks faced by participants, particularly importers and exporters, as they enter offers and bids into the market.

[134] The Panel has identified the following as the six main factors that contribute to the difference between the PD-1 MCP and the HOEP: **Supply**: i) Self-scheduling and intermittent generation forecast deviation (other than wind), ii) wind generation forecast deviation, iii) generator outages and iv) import failures/curtailments. **Demand**: v) Pre-dispatch to real-time demand forecast deviation and vi) export failures/curtailments. Imports or exports setting the PD-1 MCP can also result in price divergences as these transactions cannot set the price in real-time.

Figure A-9: Difference between HOEP & PD-1 MCP

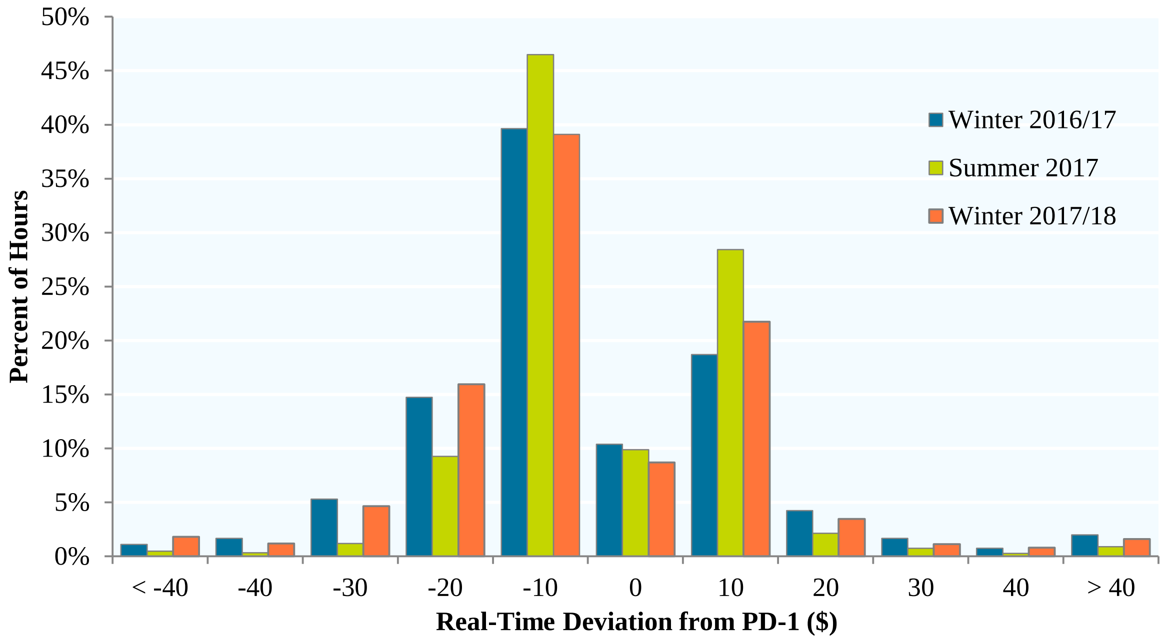


Figure A-9 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Winter 2017/18, Summer 2017 and Winter 2016/17 Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-1 MCP and the HOEP, as well as the categories where the absolute difference between the PD-1 MCP and the HOEP exceeded ±$40/MWh. Positive differences on the horizontal axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease.

Average demand forecast deviation, the most significant source of deviation between PD-1 MCP and HOEP, worsened slightly in the Winter 2017/18 Period relative to the Winter 2016/17 Period. The next most significant source of deviation, wind forecasts, improved between the Winter 2016/17 and Winter 2017/18 Periods. Total wind output in the Winter 2017/18 Period was about the same as the Winter 2016/17 Period. As such, the decrease in the rate of deviation of the wind forecast in the Winter 2017/18 Period was due to the increase in average energy demand relative to the average wind forecast deviation. Self-scheduling and intermittent forecast deviation, as well as net export curtailments, also improved.

Table A-2: Factors Contributing to Differences between PD-1 MCP & HOEP

Factor	**Winter 2017/18: Average Absolute Difference**		**Summer 2017: Average Absolute Difference**		**Winter 2016/17: Average Absolute Difference**	
	MW	**% of Ontario Demand**	**MW**	**% of Ontario Demand**	**MW**	**% of Ontario Demand**
Ontario Average Demand	15,869		14,629		15,420	
Forecast Deviation	225	1.42%	221	1.51%	195	1.26%
Self-Scheduling and Intermittent Forecast Deviation (Excluding Wind)	14	0.09%	14	0.10%	18	0.12%
Wind Forecast Deviation	131	0.83%	131	0.90%	185	1.20%
Net Export Failures/Curtailments	61	0.38%	63	0.43%	88	0.57%

Table A-2 displays the average absolute difference between PD-1 and real-time for all of the above-noted factors, save for the effect of generator outages. Generator outages tend to be infrequent relative to the other factors, although short-notice outages can have significant price effects. Ontario demand is also included to provide a relative sense of the size of the deviations.

The three-hour ahead pre-dispatch (PD-3) MCP is the last price signal seen by the market prior to the closing of the offer and bid window. Changes in price between PD-3 and HOEP are particularly relevant to non-quick start facilities and energy limited resources, both of which rely on pre-dispatch prices to make operational decisions.[135] Price changes are also important to intertie traders, whose bids and offers are often informed by pre-dispatch prices in Ontario.

[135] Energy limited resources constitute a subset of generation facilities that experience fuel restrictions such that they cannot operate at capacity for the entire day but can optimize their production over their storage horizons. For example, some hydroelectric facilities regularly experience fuel restrictions due to limited water availability.

Figure A-10: Difference between HOEP & PD-3 MCP

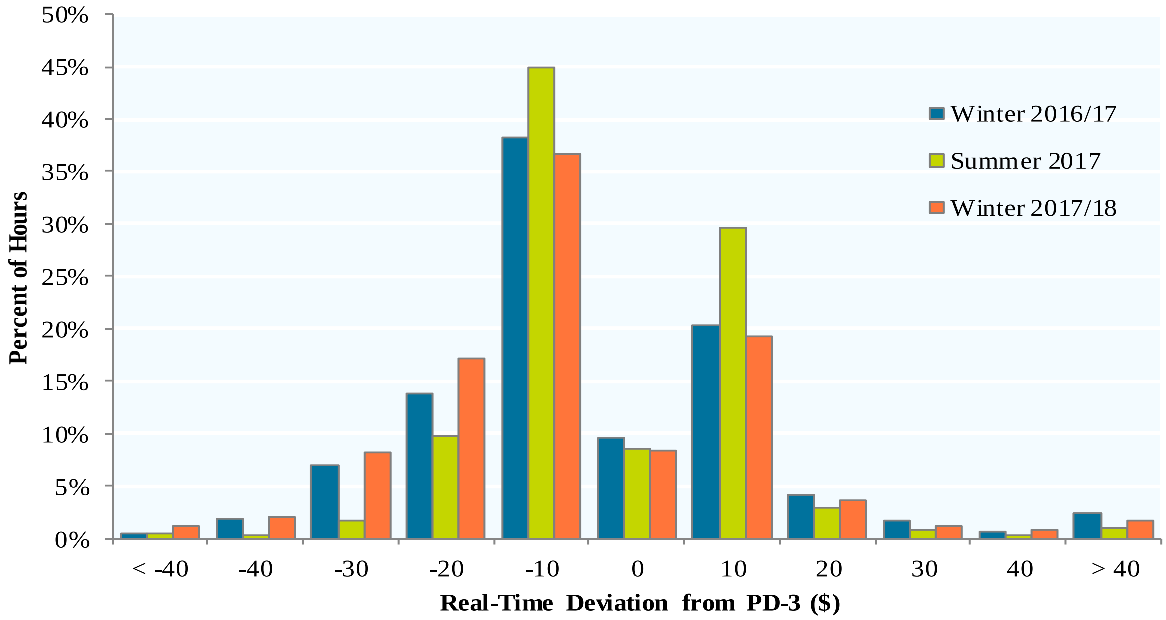


Figure A-10 presents the frequency distribution of differences between the HOEP and the PD-3 MCP during the Winter 2017/18, Summer 2017 and Winter 2016/17 Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-3 MCP and the HOEP, as well as the categories where the absolute difference between the PD-3 MCP and the HOEP exceeded ±$40/MWh. Positive differences on the x-axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease from pre-dispatch to real-time.

PD-3 prices were within $10/MWh of the real-time MCP in 65% of hours in the Winter 2017/18 Period, down slightly from 68% of hours in the Winter 2016/17 Period. However, the average absolute deviation between PD-3 and real-time MCPs was lower in the Winter 2017/18 Period ($10.35/MWh) compared to the Winter 2016/17 Period ($11.35/MWh).

Figure A-11: Monthly GA by Component

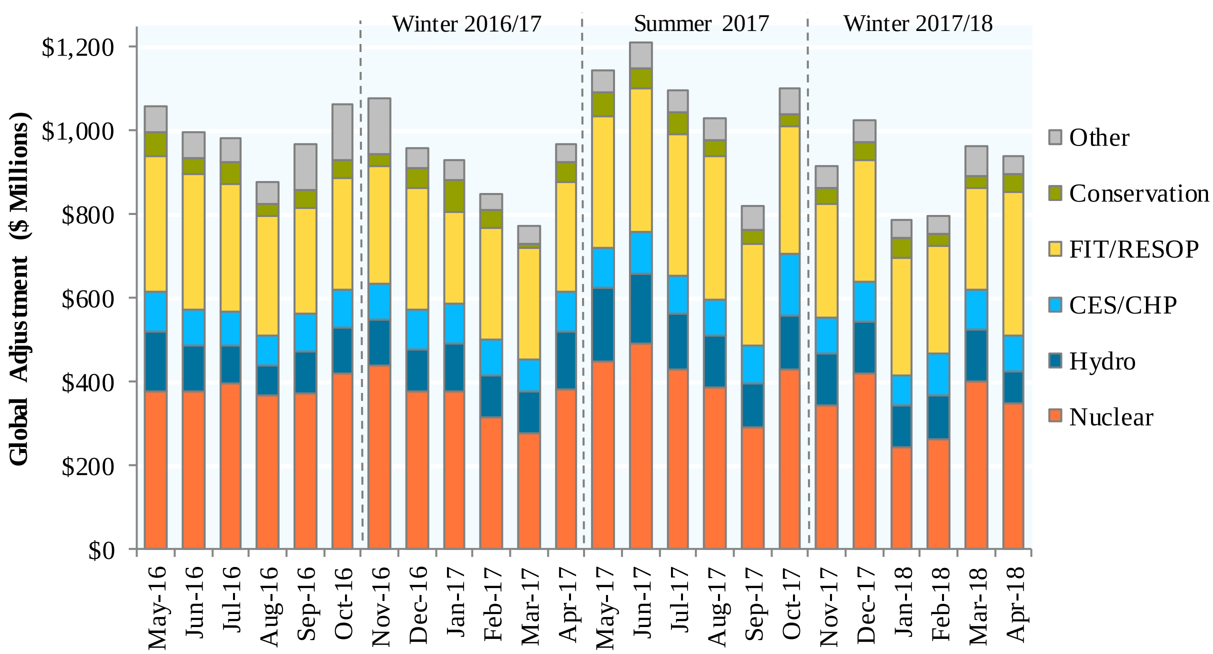


Figure A-11 plots the payments to various resources recovered through the GA each month by component for the previous two years.

The total GA is divided into six components:

- Payments to nuclear facilities (Bruce Nuclear GS and OPG's nuclear assets);
- Payments to holders of Clean Energy Supply (CES) and Combined Heat and Power (CHP) contracts;
- Payments to regulated or contracted hydroelectric generation;
- Payments to holders of contracts for renewable power (Feed-in Tariff, including microFIT (collectively FIT), and the Renewable Energy Standard Offer Program (RESOP));
- Payments related to the IESO's conservation programs; and
- Payments to others (including to holders of non-utility or NUG contracts and OPG's Lennox GS).

The total GA throughout the Winter 2017/18 Period was about 2.3% less than the total GA during the Winter 2016/17 Period, falling from $5.5 billion to $5.4 billion. The increase in demand between the Winter 2016/17 and Winter 2017/18 Periods caused the market revenues of nuclear and hydro generators under revenue regulation to increase, resulting in lower payments to meet the requirements of these generators through GA charges. The relative contribution of each component of GA remained largely unchanged.

Hourly uplift components are charged to wholesale consumers (including distributors) based on their share of total hourly demand, while monthly uplift components are charged to wholesale consumers (including distributors) based on their share of total daily or monthly demand.[136]

Total uplift increased in the Winter 2017/18 Period compared to the previous three reporting periods. Total uplift in the Winter 2017/18 Period was $241 million, compared to $191 million in the Summer 2017 Period, $199 million in the Winter 2016/17 Period and $235 million in the Summer 2016 Period. The increase in total hourly uplift was primarily driven by an increase in Congestion Management Settlement Credit (CMSC) and Intertie Offer Guarantee (IOG) payments. The increase in total monthly uplift was primarily driven by an increase in cost guarantee payments. Compared to the Winter 2016/17 Period, total CMSC, IOG and cost guarantee payments rose by $13.6 million, $15.5 million and $14.1 million (or by 29%, 148%, and 62%), respectively.

[136] This applies to all monthly and daily uplifts with the exception of costs associated with DR. The costs of DR are allocated with the same methodology as the GA, where Class A consumers pay the fraction of costs corresponding to their fraction of Ontario demand during the 5 highest demand peaks of the year, and Class B consumers are billed the remaining sum volumetrically.

Figure A-12: Total Uplift Charge by Component on a Monthly Basis

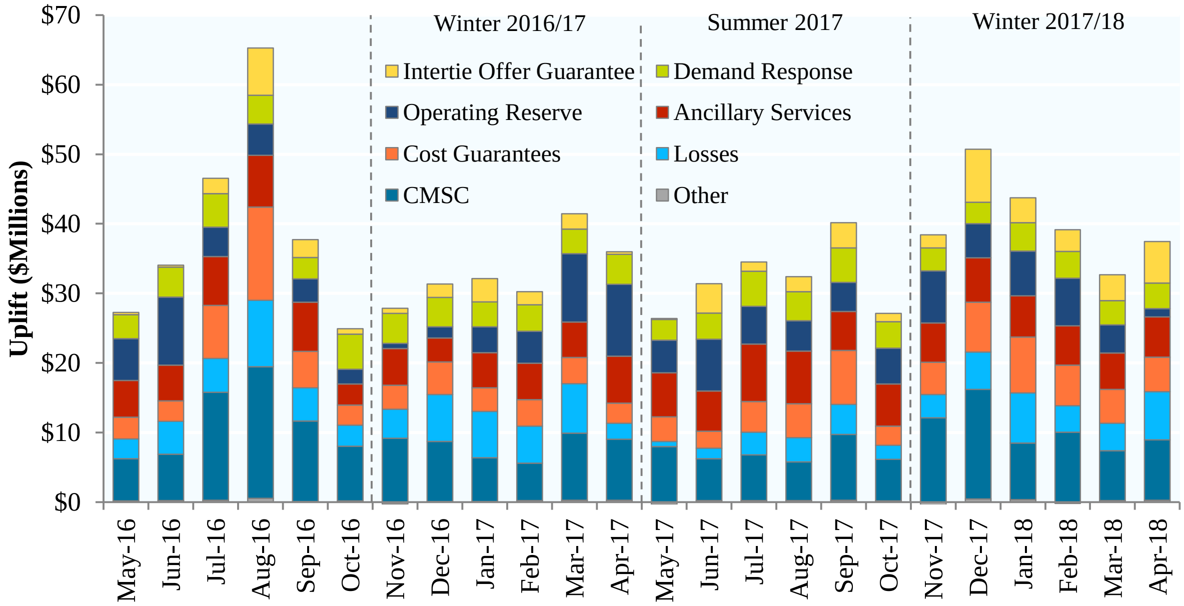


Figure A-12 presents the total uplift charges by component on a monthly basis for the previous two years. This includes both hourly and monthly uplift, which were displayed in separate figures in previous Panel reports.[137] In this figure, monthly ancillary services payments are combined with hourly voltage support payments as Ancillary Services, while PCG and RT-GCG payments are combined as Cost Guarantees.

The increase in CMSC payments in the Winter 2017/18 Period can likely be explained in part by the increase in the demand compared to the Winter 2016/17 Period, and in part by the higher frequency of anomalous events that drove up CMSC payments compared to the Winter 2016/17 Period, as described in Chapter 2 of this report, Analysis of Anomalous Market

[137] **Hourly uplift components include**: CMSC payments; IOG payments; OR payments; Voltage support payments; and Transmission losses. **Monthly uplift components include:** Payments for ancillary services; Guarantee payments to generators under the Day-Ahead Production Cost Guarantee (PCG) and RT-GCG programs; Payments for the IESO's DR capacity, such as capacity procured through the DR auction; and Other, which includes charges and rebates such as compensation for administrative pricing and the local market power rebate, among others.

Outcomes. A majority of the increase in IOG payments in the Winter 2017/18 Period can be attributed to a series of hours in December 2017 and April 2018, in which there was a large volume of Day-Ahead Commitment Process imports scheduled at the same time that the intertie scheduling limit over Québec interties was reduced. These hours are a part of a series of 21 hours between January 1, 2017 and September 30, 2018 that are described in the Panel's previous Monitoring Report, in which an average of $1,440,000 in IOG payments per hour were made.[138] The increase in cost guarantee payments was predominantly driven by an increase in RT-GCG payments in the Winter 2017/18 Period relative to the Winter 2016/17 Period.

Figure A-13: Average Monthly OR Prices by Category

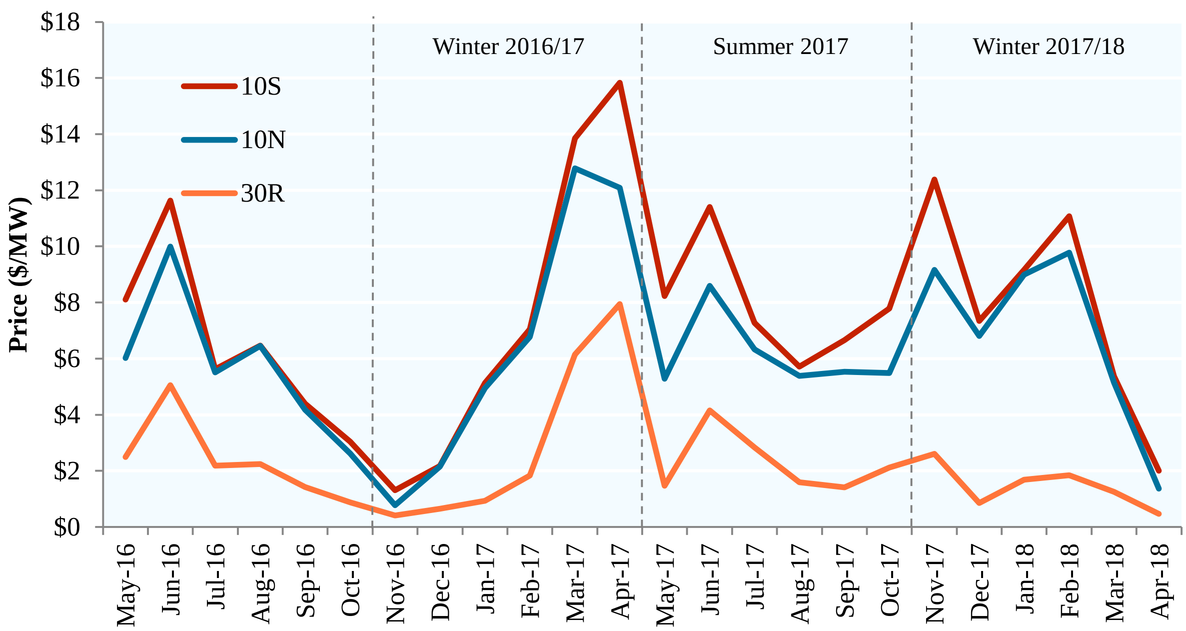


Figure A-13 plots the monthly average OR price for the previous two years for the three OR markets: 10-minute spinning (10S), 10-minute non-spinning (10N) and 30 minute (30R).

[138] See the Panel's Monitoring Report 31 (Nov 2016-Apr 2017) published April 2019, Section 2.1, "Extreme Congestion Prices Over the Interties": https://www.oeb.ca/sites/default/files/msp-monitoring-report-20191219.pdf

The three OR markets are co-optimized with the energy market, so prices in these markets tend to be subject to similar dynamics. The OR demand is non-discretionary because of reliability standards set by the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC). The IESO must schedule sufficient OR to allow the grid to recover from the single largest contingency (such as the loss of the largest generator) within 10 minutes, plus additional OR to recover from half of the second largest contingency within 30 minutes.

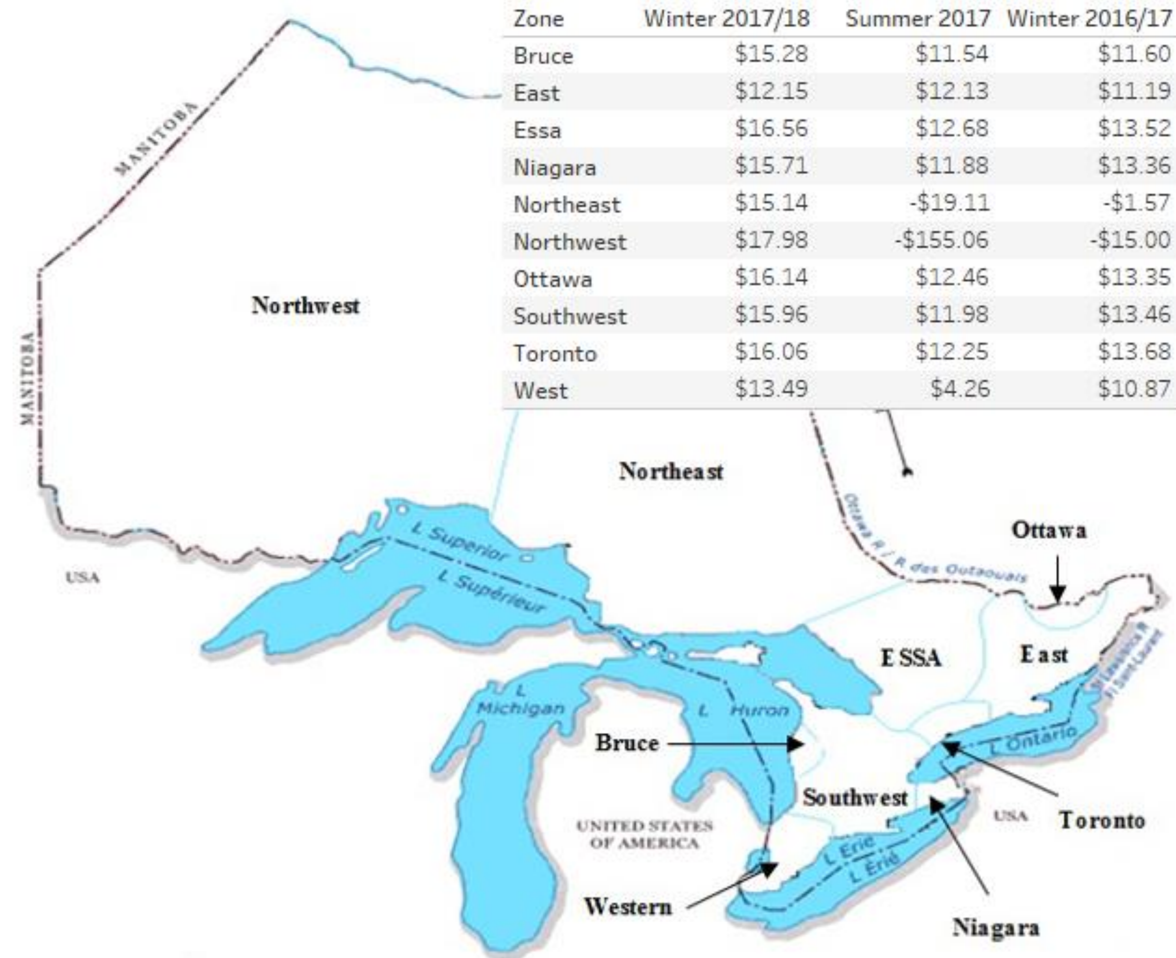
Average 10N and 10S OR prices increased slightly in the Winter 2017/18 Period compared to the Winter 2016/17 Period, from $7.55/MW and $6.59/MW to $7.89/MW and $6.88/MW, respectively. In contrast, 30R prices decreased, from an average of $2.99/MW in the Winter 2016/17 Period to $1.45/MW in the Winter 2017/18 Period. Fewer MW of all three classes of OR were offered by Market Participants in the Winter 2017/18 Period compared to the Winter 2016/17 Period, and the average offer prices associated with the offers of all three classes of OR were higher in the Winter 2017/18 Period than they were in the Winter 2016/17 Period. Fewer offers and higher offer prices in the OR markets are typically associated with higher MCPs in the OR markets, as reflected in the increase in the prices of 10N and 10S OR between the Winter 2016/17 and Winter 2017/18 Periods.

The average 30R in the Winter 2016/17 Period was raised by price spikes in both the energy market and the OR markets that occurred in March and April of 2017.[139] Because the 30R price is much lower on average than the 10N and 10S prices, the increase in the 30R price during these price spikes was proportionally much larger than the increase in the 10N and 10S prices, heavily influencing the average 30R price in the Winter 2016/17 Period. This influence on the 30R price outweighed the increase in the average 30R price associated with the decrease in the quantity of offers and increase in the average offer price in the Winter 2017/18

[139] For more information on the price spikes described, see the Panel's Monitoring Report 30 (Nov 2016-Apr 2017) published April 2019, Chapter 3, Section 1.1, "Summary of High-Priced Hours": https://www.oeb.ca/sites/default/files/msp-monitoring-report-20190429.pdf

Period, resulting in the decrease of the average 30R price between the Winter 2016/17 and Winter 2017/18 Periods.

Figure A-14: Average Internal Nodal Prices by Zone



Zone	Winter 2017/18	Summer 2017	Winter 2016/17
Bruce	$15.28	$11.54	$11.60
East	$12.15	$12.13	$11.19
Essa	$16.56	$12.68	$13.52
Niagara	$15.71	$11.88	$13.36
Northeast	$15.14	-$19.11	-$1.57
Northwest	$17.98	-$155.06	-$15.00
Ottawa	$16.14	$12.46	$13.35
Southwest	$15.96	$11.98	$13.46
Toronto	$16.06	$12.25	$13.68
West	$13.49	$4.26	$10.87

Figure A-14 illustrates the average nodal prices of Ontario's ten internal zones for the Winter 2017/18, Summer 2017 and Winter 2016/17 Periods.[140]

[140] Each zone has a series of nodes, with each node having its own shadow price. The average price for each zone is calculated by taking the simple average of the nodes within that zone over every hour in the monitoring period, and then taking a simple average of the price calculated for each hour in the monitoring period associated with that particular zone.

Nodal prices approximate the marginal cost of electricity in each region and reflect Ontario's internal transmission constraints. High average nodal prices are generally caused by expensive or limited supply while low average nodal prices are generally caused by cheaper or abundant supply.

In general, monthly average nodal prices outside the two northern zones are similar and move together. Most of the time, the nodal prices in the Northwest and Northeast zones are significantly lower than in the rest of the province because there is more low-cost generation than there is demand in these zones, as well as insufficient transmission to transfer this low-cost surplus power to the southern parts of the province.

In addition, some hydroelectric facilities operate under must-run conditions, generating at certain levels of output for safety, environmental or regulatory reasons. Under such conditions, Market Participants offer the must-run energy at negative prices in order to ensure that the units are economically selected and scheduled.

Nodal prices in all zones were higher in the Winter 2017/18 Period compared to the Winter 2016/17 Period, which is to be expected during a period of higher demand. The nodal price in the Northwest zone increased dramatically, becoming positive. This is likely explained in part by the large increase in demand within the Northwest region, which rose by about 12.6% on average between the Winter 2016/17 and Winter 2017/18 Periods. The increase in Northwest nodal prices could also be explained in part by an increase in the nodal prices of resources near the Ontario-Manitoba intertie, suggesting that there were more opportunities to economically export power to Manitoba relative to the Winter 2016/17 Period.

Figure A-15: Import Congestion by Intertie

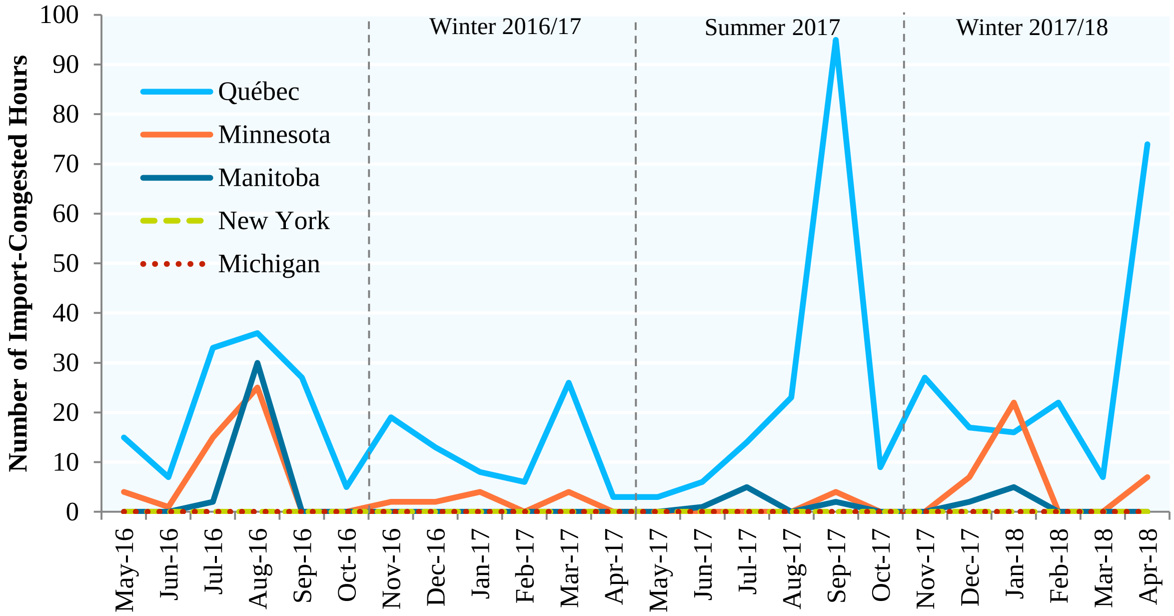


Figure A-15 reports the number of hours per month of import congestion, by intertie for the previous two years. Unless otherwise stated, all references to the Québec intertie in this chapter refer to the Outaouais intertie.

When an intertie has a greater amount of economic net import offers (or economic net export bids) than its PD-1 transfer capability, the intertie will be import (or export) congested.

For a given intertie, importers are paid the intertie zonal price (IZP), while exporters pay the IZP. The difference between the IZP and the MCP is called the Intertie Congestion Price (ICP). The ICP for a given hour is calculated in PD-1 when there are more economic transactions than the intertie transmission lines can accommodate. The ICP is positive when there is export congestion and negative when there is import congestion.

Only the Québec, Minnesota, and Manitoba interties experienced import congestion during the Winter 2017/18 Period. The Québec interties saw an increase in the number of import-congested hours from 75 hours in the Winter 2016/17 Period to 163 hours in the Winter 2017/18 Period. Congestion on the Québec interties was above average throughout April 2018, reaching 74 hours of import congestion in total. Ontario faced higher energy prices throughout the Winter 2017/18 Period compared to the Winter 2016/17 Period in part due to cold weather, increasing the amount of economic import transactions between Ontario and Québec during the Winter 2017/18 Period. The effects of cold weather on the HOEP were most significant in January and April of 2018, whereas Québec only faced higher energy prices in January due to cold weather. As a result, April had the most economic import offers and thus more hours of import congestion.

Figure A-16: Export Congestion by Intertie

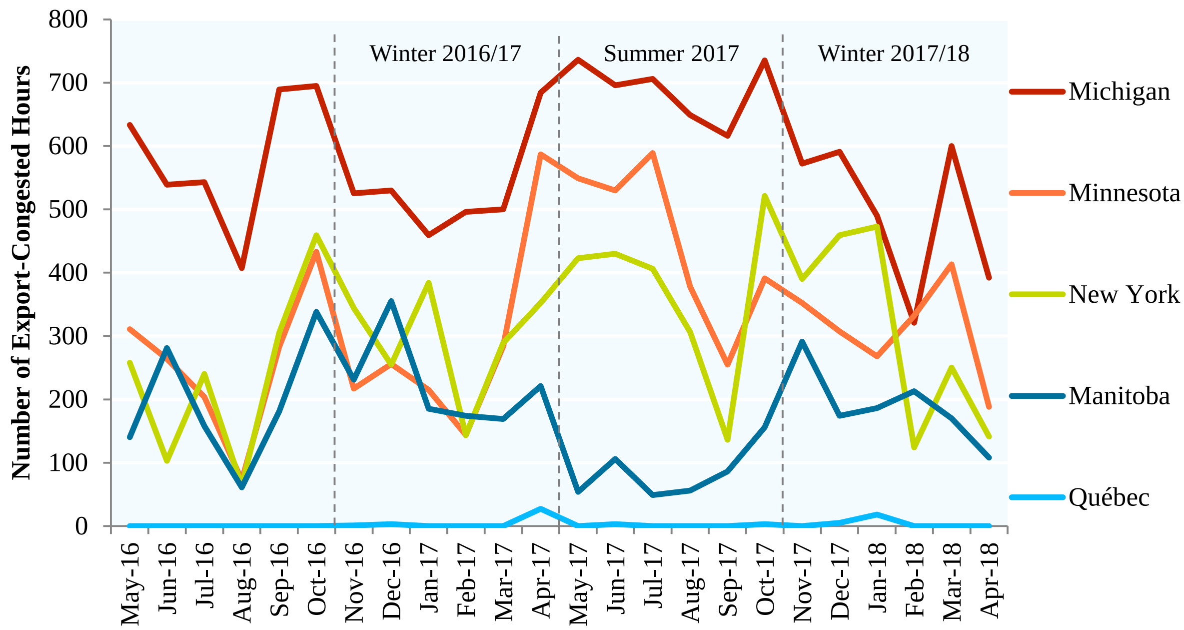


Figure A-16 reports the number of hours per month of export congestion, by intertie for the previous two years. Unless otherwise stated, all references to the Québec intertie in this chapter refer to the Outaouais intertie.

Total export congestion decreased slightly in the Winter 2017/18 Period relative to the Winter 2016/17 Period. Compared to the Winter 2016/17 Period, export congestion fell in Manitoba and Michigan by 14% and 7%, whereas export congestion rose in Minnesota and New York by 9% and 4%, respectively. Total export congestion in the Winter 2017/18 Period was much lower than the Summer 2017 Period, due to the lower than average HOEPs in that period. On average, export congestion between Ontario and another jurisdiction was higher when the ICP between that jurisdiction and Ontario was high.

Table A-3: Monthly Electricity Spot Prices – Ontario & Surrounding Jurisdictions

Date	Ontario (HOEP) ($/MWh)	Manitoba ($/MWh)	Michigan (MISO) ($/MWh)	Minnesota (MISO) ($/MWh)	New York (NYISO) ($/MWh)	PJM ($/MWh)
November 2017	12.99	44.02	48.65	45.51	30.10	35.09
December 2017	19.32	31.62	37.18	32.78	44.86	52.60
January 2018	30.32	41.75	46.57	43.35	89.51	87.50
February 2018	18.01	32.15	31.64	32.33	27.99	31.25
March 2018	16.50	27.52	34.45	29.09	27.17	32.60
April 2018	28.56	31.25	39.52	33.46	38.31	40.01

Table A-3 lists the average hourly real-time spot prices for electricity, by month, in Ontario and the surrounding external jurisdictions with which electricity intertie traders operating in Ontario commonly trade. The Ontario price reported reflects only the HOEP and does not include the GA or uplift. Québec does not operate a wholesale market, does not publish prices, and thus is not included in Table A-3. The prices listed for each jurisdiction reflect the marginal price of electricity excluding costs associated with capacity as traders do not pay these costs.

Absent congestion at an intertie, importers receive, and exporters pay, the HOEP when transacting in Ontario. If there is congestion, however, importers and exporters in Ontario receive or pay the IZP rather than the HOEP.

The external prices reported are the real-time locational-marginal prices that correspond with the node on the other side of Ontario's intertie with each jurisdiction.

As it has been for several years, the average HOEP was lower than the market price in all of Ontario's neighbouring jurisdictions in every month in the Winter 2017/18 Period. This is due in part to the capacity surplus in Ontario, and in part to characteristics in the market that depress prices. Accordingly, Ontario remained a net exporter for every month in the Winter 2017/18 Period.

Figure A-17: Import Congestion Rent & TR Payouts by Intertie

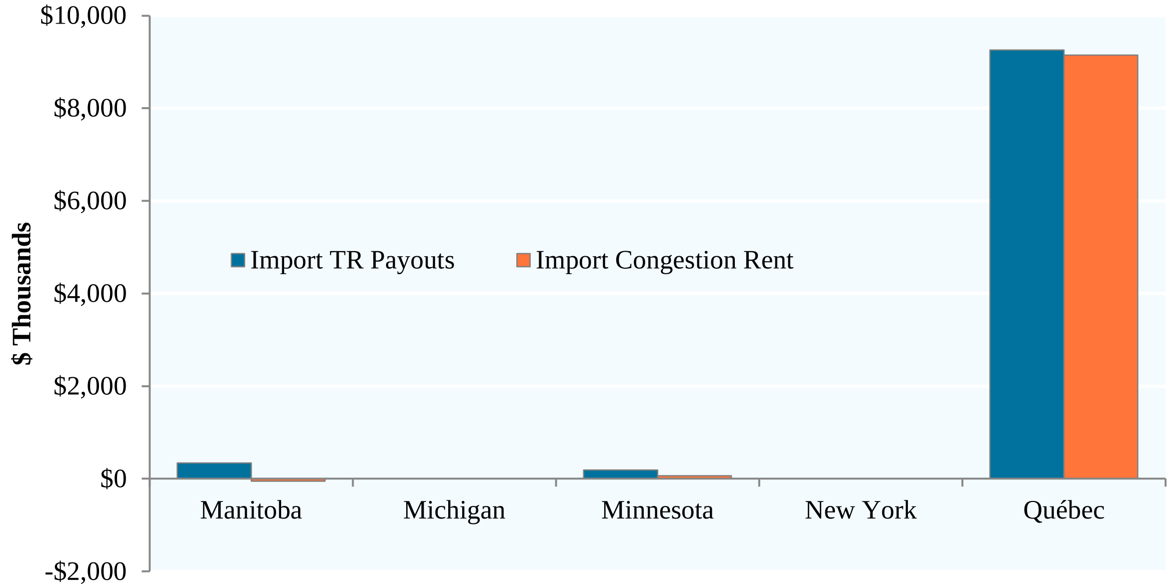


Figure A-17 compares the total import congestion rent collected to total TR payouts by intertie for the Winter 2017/18 Period.

An IZP is less than the Ontario price when an intertie is import congested; the difference in prices is the ICP and is equal to the difference (if any) between the PD-1 MCP and the PD-1 IZP. While the importer is paid the lower IZP, the buyer in the wholesale market still pays the HOEP. The difference between the amount collected from the purchaser and the amount paid to the importer in such a case is import “congestion rent”. Congestion rent accrues to the IESO’s TRCA.

To enable intertie traders to hedge against the risk of price fluctuations due to congestion, the IESO administers TR auctions. TRs are sold by intertie and direction (import or export) for periods of one month or one year. The owner of a TR is entitled to a payment (or “payout”) equal to the ICP multiplied by the amount of TRs they hold every time congestion occurs on the intertie in the direction for which they own a TR.

While TR payouts should theoretically be offset by congestion rent collected, in practice this is often not the case. Any shortfalls are covered primarily by TR auction revenues, which are the proceeds from selling TRs (a payment into the TRCA).

Interties with a high frequency of import congestion hours (see Figure A-15) do not necessarily correlate with high import TR payouts and import congestion rent, primarily because of the differences in intertie capacity (and thus TRs sold) at each intertie.

Total import TR payouts in the Winter 2017/18 Period were $9.8 million, while total import congestion rent was $9.2 million, creating a congestion rent shortfall of $624,000. As such, the TR market for imports was close to balanced. Québec saw a modest congestion rent shortfall of $109,000, and Minnesota and Manitoba saw congestion rent shortfalls of $126,000 and $389,000.

Figure A-18: Export Congestion Rent & TR Payouts by Intertie

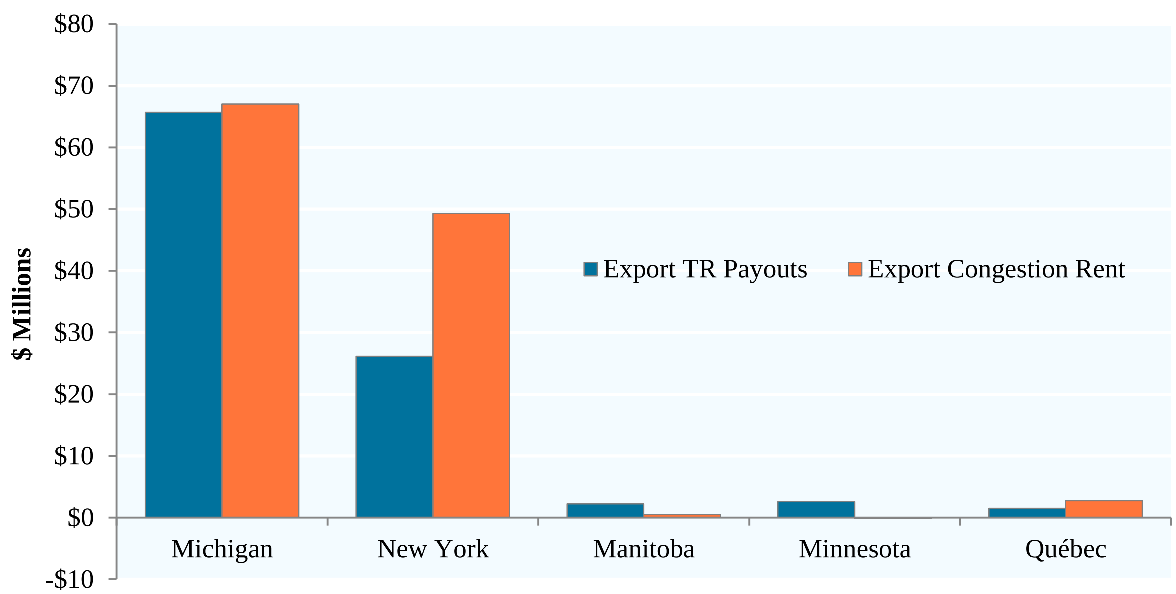


Figure A-18 compares the total export congestion rent collected to total TR payouts by intertie for the Winter 2017/18 Period.

Export TR payouts in the Winter 2017/18 Period totalled $98.2 million, while export congestion rent totalled $119.4 million. This $21.2 million surplus of congestion rent is primarily due to the $23 million imbalance between congestion rent and TR Payouts on the New York intertie. This surplus was largely due to more megawatts of transmission being available on the New York intertie than were sold as TRs throughout the period, which was also the case in the previous period. Exports to Québec incurred a congestion rent surplus of $1.2 million, and exports to Manitoba and Minnesota incurred congestion rent shortfalls of $1.7 million and $2.6 million, respectively. Michigan had a relatively small congestion rent surplus of $1.3 million, despite having very high TR payouts and congestion rent.

Table A-4: Average 12-Month TR Auction Prices by Intertie & Direction

Direction	Auction Date	Period TRs are Valid	Manitoba ($/MW)	Michigan ($/MW)	Minnesota ($/MW)	New York ($/MW)	Québec ($/MW)
Import	May-17	Jul-17 to Jun-18	1,480	47	1,707	148	2,280
	Aug-17	Oct-17 to Sep-18	560	132	1,779	188	3,632
	Nov-17	Jan-18 to Dec-18	340	223	1,638	59	4,908
	Feb-18	Apr-18 to Mar-19	925	140	2,580	85	6,332
Export	May-17	Jul-17 to Jun-18	29,008	131,418	46,357	56,743	2,473
	Aug-17	Oct-17 to Sep-18	20,148	123,254	52,842	56,204	1,927
	Nov-17	Jan-18 to Dec-18	33,106	139,460	63,117	57,141	2,896
	Feb-18	Apr-18 to Mar-19	26,374	128,674	54,443	52,440	2,206

Table A-4 lists the average auction prices per megawatt of long-term (12-month) TRs for each intertie in either direction for each auction since May 2017. These are the TRs that would have been valid during the Winter 2017/18 Period. If an auction is efficient, the price paid per megawatt of TRs should reflect the expected payout from owning that TR for the period. Prices signal Market Participant expectations of intertie congestion conditions for the forward period.

Compared to the May 2017 auction, long-term export TR prices decreased modestly across all jurisdictions, except Minnesota, by the February 2018 auction, after increasing during the

November 2017 auction. Long-term export TR prices for Minnesota increased by 17% since May 2017, after peaking in November 2017. Long-term import TR prices increased sharply for Québec, indicating that TR Market Participants expected import congestion to decrease into the Summer 2018 and Winter 2018/19 Periods. Long-term import TR prices also increased for Minnesota, and decreased in Manitoba and New York. Export TR prices remained higher for every jurisdiction except Québec, indicating that traders expected import congestion to surpass export congestion in Québec through to Winter 2018/19, and for export congestion to surpass import congestion everywhere else.

Short-term import TR prices remained relatively constant throughout the Winter 2017/18 Period. However, short-term import TR prices did increase notably for Minnesota. Short-term export TR prices were more volatile – between January and February 2018, with prices rising sharply in Michigan, New York and Québec. Prices were most volatile for Michigan, changing by more than $3,000/MW frequently between months in the Winter 2017/18 Period. Short-term export TR prices showed a steadily increasing trend for Manitoba, rising from $1,836/MW in November 2017 to $3,725/MW in April of 2018. In several months during the Summer 2017 Period, the Minnesota intertie had little to no capacity due to outages, preventing TRs from being sold.

Table A-5: Average One-Month TR Auction Prices by Intertie & Direction

Direction	Period TRs are Valid	Manitoba ($/MW)	Michigan ($/MW)	Minnesota ($/MW)	New York ($/MW)	Québec ($/MW)
Import	May-17	20	4	45	22	86
	Jun-17	77	4	79	22	108
	Jul-17	82	6	-	24	260
	Aug-17	90	0	-	1	357
	Sep-17	65	7	64	2	265
	Oct-17	14	3	-	2	128
	Nov-17	50	2	55	8	252
	Dec-17	20	2	64	13	260
	Jan-18	44	11	222	21	260
	Feb-18	54	0	420	22	235
	Mar-18	60	1	185	10	260
	Apr-18	11	4	245	15	252
Export	May-17	2,983	14,962	5,820	6,002	5
	Jun-17	2,599	11,570	-	5,665	7
	Jul-17	3,802	12,649	-	5,385	8
	Aug-17	2,135	12,689	-	6,220	11
	Sep-17	1,320	11,887	-	4,680	19
	Oct-17	3,058	12,983	-	4,820	5
	Nov-17	1,836	11,543	-	5,076	10
	Dec-17	2,835	7,415	5,260	2,900	111
	Jan-18	3,006	7,821	4,546	5,555	117
	Feb-18	2,964	12,036	5,416	7,778	650
	Mar-18	3,147	8,411	4,288	4,918	164
	Apr-18	3,725	13,615	5,053	5,472	5

Table A-5 lists the auction prices per megawatt of short-term (one-month) TRs for each intertie in either direction for each auction during the Winter 2017/18 and Summer 2017 Periods. Auction prices signal Market Participant expectations of intertie congestion conditions for the forward period.

Figure A-19: The TRCA

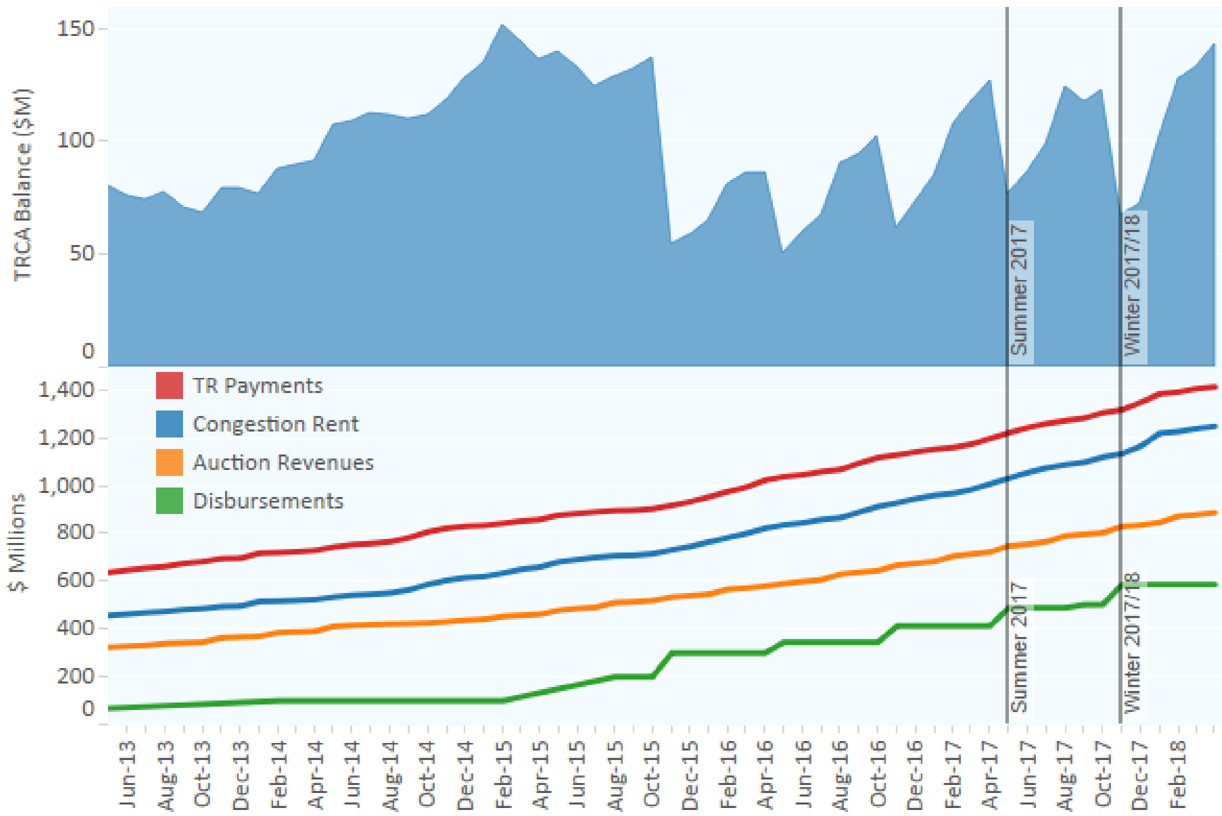


Figure A-19 shows the estimated balance in this account at the end of each month for the previous five years, as well as the cumulative effect of each type of transaction impacting the account.

The balance of the TRCA increased to $145.3 million at the end of the Winter 2017/18 Period, up from $123.8 million at the end of the Summer 2017 Period. The April 2018 balance was $125.3 million above the reserve threshold of $20 million set by the IESO Board of Directors. This change in balance was composed of:

1. $213.6 million in revenue, specifically:
    - $128.6 million in congestion rent

- $83.9 million in auction revenues
- $1.1 million in interest

2. $192.1 million in debits, specifically:

    - $108.0 million in TR payouts
    - $84.1 million in disbursements to Ontario consumers and exporters.

Compared to the Summer 2017 Period, there was an increase in credits and a small decrease in debits during the Winter 2017/18 Period. This increase to the TRCA balance was largely due to higher congestion rent relative to TR payouts associated with export congestion on the New York intertie in the Winter 2017/18 Period.

A.2 Demand

Figure A-20: Monthly Ontario Energy Demand by Class A & Class B Consumers

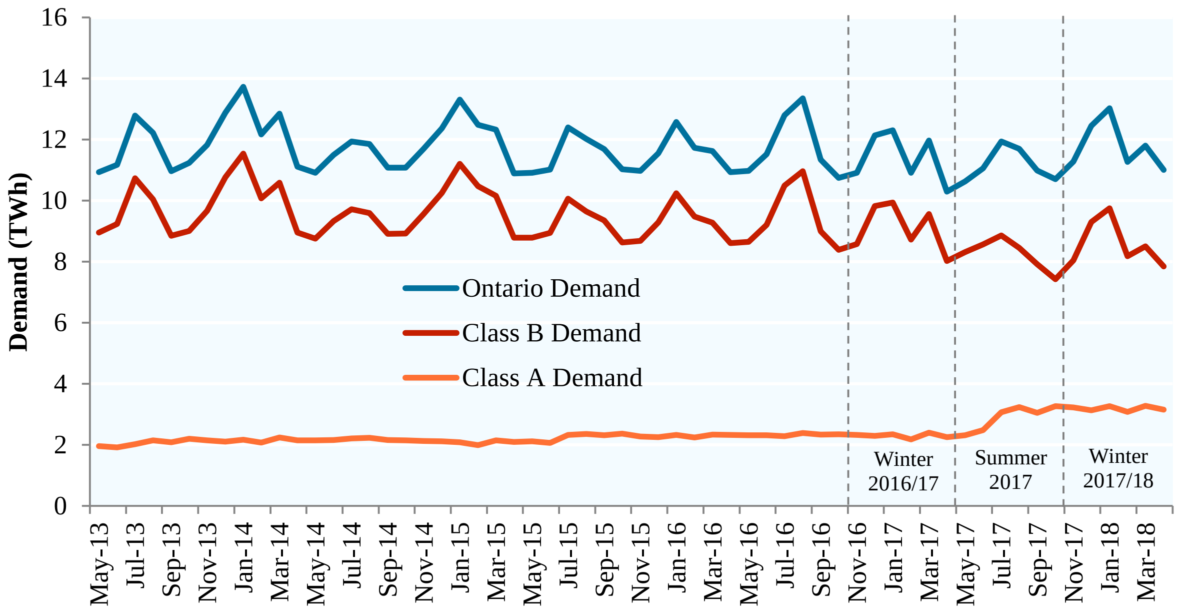


Figure A-20 displays energy consumption by all Ontario consumers in each month of the past five years, broken down by demand from Class A and Class B consumers. The figure represents total Ontario demand –not grid-connected demand – in that it includes demand satisfied by embedded generators.[141]

Total demand in the Winter 2017/18 Period was 70.8 TWh – 3.4% higher than the total demand of 68.5 TWh in the Winter 2016/17 Period. This increase in demand in the Winter 2017/18 Period was caused partially by the weather, which was colder on average than the Winter 2016/17 Period, and partially caused by relatively strong economic growth in Ontario at the beginning of 2018.

[141] Class A demand may be understated as the Panel does not have access to behind-the-meter generation data, which serves to offset demand from the grid. For more information, see the Panel's Monitoring Report 24 (Nov 2013-Apr 2014) published April 2015, pages 105-109, and the Panel's Industrial Conservation Initiative Report, published December 2018: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf and https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

Compared to the Winter 2016/17 Period, Class A demand grew significantly and Class B demand fell significantly. This is because the threshold for participation in Class A was lowered as part of the former government's Fair Hydro Plan, prompting additional Market Participants in industry to move from Class B into Class A. Class A demand was 5.3 TWh higher in the Winter 2017/18 Period than the Winter 2016/17 Period, whereas Class B demand was 3.0 TWh lower in the Winter 2017/18 Period than the Winter 2016/17 Period.

A.3 Supply

This section presents data on generating capacity, actual generation, and OR supply for the Winter 2017/18 Period relative to previous years.

Table A-6: Changes in Generating Capacity

Generation Type	Grid-connected		Distribution-level (Embedded)	
	Increase (MW)	Total (MW)	Increase (MW)	Total (MW)
Nuclear	-	13,009	-	-
Natural Gas	-	10,277	-	-
Hydro	-7	8,473	37	277
Wind	100	4,313	11	591
Solar	-	380	48	2,057
Biofuel	-	495	-	109
Gas-Fired and Combined Heat and Power	-	-	2	271
Energy from Waste	-	-	-	24
Total	93	36,946	98	3,329

Table A-6 lists the quantity of nameplate generating capacity that completed commissioning and was added to the IESO-controlled grid's total capacity during the fourth quarter of 2017 and the first quarter of 2018, as well as the quantity of nameplate IESO contracted generating capacity that was added at the distribution level.[142] Total capacity of each type at the end of the Winter 2017/18 Period is also shown.

Little new capacity was added to the Ontario generation fleet at either the IESO-controlled grid or the distribution level. The capacity added was mostly variable generation offered at low prices, potentially contributing to the continuation of the prevailing low wholesale spot prices in Ontario.

[142] Grid-connected and embedded capacity totals were obtained from the Q1 2018 quarterly Ontario Energy Report, available at: http://www.ontarioenergyreport.ca/index.php

Figure A-21: Resources Scheduled in the Real-Time Market (Unconstrained)

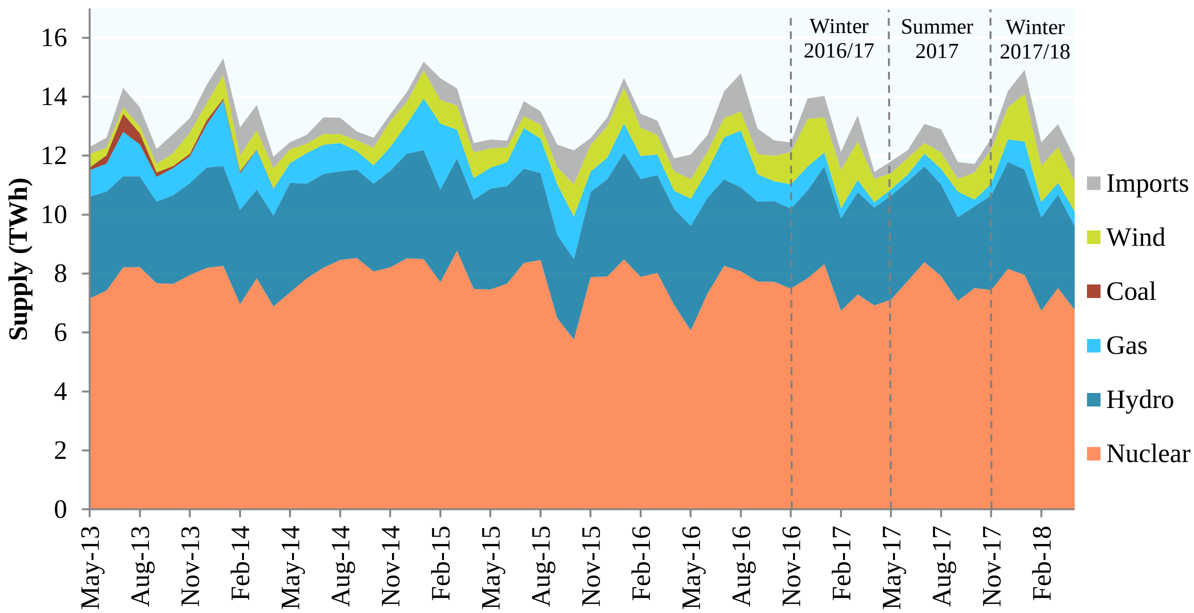


Figure A-21 displays the share of real-time unconstrained production schedules from May 2013 to April 2018 by resource or transaction type: wind, coal, gas-fired, hydroelectric, nuclear and imports.[143] Changes in the resources scheduled may be the result of a number of factors, such as changes in market demand or seasonal fuel variations (for example, during the spring snowmelt or "freshet" when hydroelectric plants have an abundant supply of water).

Compared to the Winter 2016/17 Period, the Winter 2017/18 Period showed a modest increase in the output of gas-fired generators, hydroelectric generators, and use of imports: Hydroelectric output increased from 18.9 TWh to 19.6 TWh, gas generator output increased from 3.0 TWh to 3.5 TWh, and import use increased from 3.5 TWh to 4.1 TWh. Increases in the use of gas-fired generators and imports can be attributed to the increase in demand

[143] Solar and biofuel are excluded from the figure as they contribute minimally to the total grid-connected resources scheduled in real-time. Ontario has significant solar and wind generation connected at the distribution level that is not included in this figure. These embedded resources are not scheduled in IESO-Administered Markets. Average output from these embedded generators was approximately 0.5 TWh per month; due to data constraints, this quantity cannot be broken down by type of generation.

between the Winter 2016/17 and Winter 2017/18 Periods, as such an increase would result in the use of more expensive resources to supply the energy needed to meet this demand.

Figure A-22: Average Hourly OR Scheduled by Resource Type

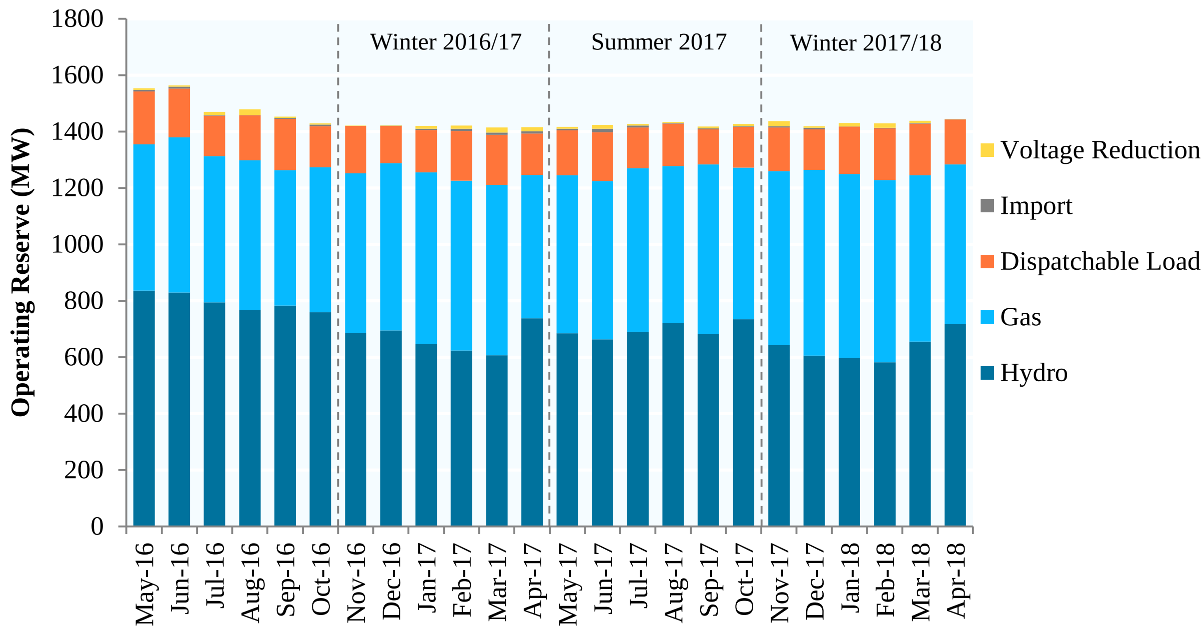


Figure A-22 displays the share of real-time unconstrained OR schedules from May 2016 to April 2018 by resource or transaction type: hydroelectric, gas-fired, imports, dispatchable loads, and voltage reduction (taken as a control action by the IESO).[144] Changes in the total average hourly OR scheduled reflect changes in the OR requirement over time.

The average quantity of scheduled OR has remained relatively constant compared to the Winter 2016/17 Period. On average, 1,435 MW of OR was scheduled during the Winter 2017/18 Period, compared to 1,427 MW and 1,420 MW in the Summer 2017 and Winter

[144] The IESO inserts standing offers in the OR offer stack that represent the IESO's ability to use 3% and 5% voltage reductions or forego the 30-minute OR requirement (under specific conditions) to meet OR needs. The offers have a pre-defined price and quantity and are only scheduled in real-time, never in pre-dispatch. Voltage reductions are an out-of-market control action taken by the IESO when the market cannot provide enough supply to meet forecasted demand and reserve requirements.

2016/17 Periods, respectively. Gas generators continue to be scheduled more frequently for OR, representing 43.3% of OR scheduled in the Winter 2017/18 Period, compared to 40.9% in the Winter 2016/17 Period and about 35% in both the Summer 2016 and Winter 2015/16 Periods. Hydroelectric generators were scheduled slightly less, at 44.1% of scheduled OR in the Winter 2017/18 Period compared to 46.9% in the Winter 2016/17 Period.

Figure A-23: Unavailable Generation Relative to Installed Capacity

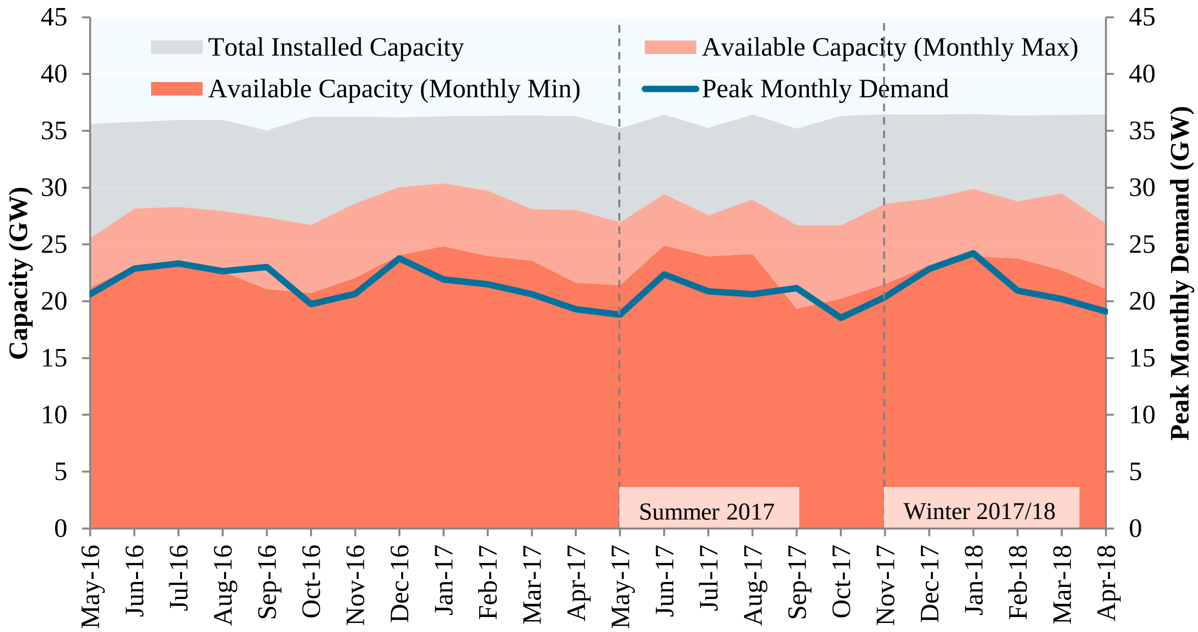


Figure A-23 plots the monthly minimum and maximum available capacity, accounting for unavailable generation capacity due to planned and forced (i.e. unforeseen) outages and de-rates, unavailable capacity from intermittent and self-scheduling generators and constrained generation capacity due to operating security limits from May 2016 to April 2018. The maximum and minimum megawatts on outage during a given month can be observed by comparing the total installed capacity to the monthly minimum and maximum available capacity, respectively. For reference, the figure also includes the monthly peak market demand, excluding demand served by imports.[145]

[145] Unavailable generation capacity data was obtained from adequacy reports published daily by the IESO. Daily, weekly and monthly market summaries published by the IESO can be found on the IESO website, available at: http://www.ieso.ca/power-data/market-summaries-archive

The Winter 2017/18 Period had, on average, 10.7 GW of unavailable capacity, which is slightly more than the average of 10.0 GW of capacity that was unavailable in the Winter 2016/17 Period. This difference was primarily driven by more outages of wind and hydro capacity in the Winter 2017/18 Period. Minimum and maximum available capacity were lower in the Winter 2017/18 by 0.66 GW and 0.38 GW on average compared the Winter 2016/17 Period, respectively.

A.4 Imports, Exports and Net Exports

This section examines import and export transactions in the unconstrained sequence, as schedules in this sequence directly affect market prices. The unconstrained schedules may not reflect actual power flows.[146]

Figure A-24: Monthly Imports and Exports, and Average Net Exports (Unconstrained)

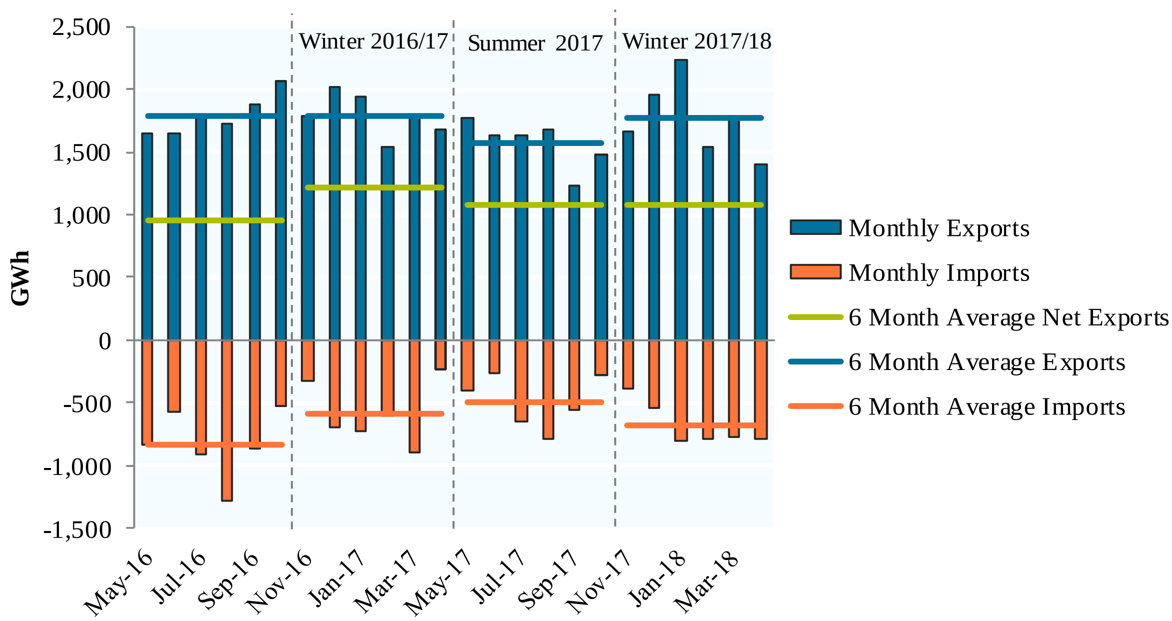


Figure A-24 plots total monthly imports and exports from May 2016 to April 2018, as well as the average monthly imports, exports and net exports calculated over each six-month reporting period during those two years. Exports are represented by positive values while imports are represented by negative values.

Ontario remained a net exporter in the Winter 2017/18 Period, with net exports of 6.49 TWh, down from 7.25 TWh in the Winter 2016/17 Period. Compared to the Winter 2016/17 Period, exports fell by 0.16 TWh, and imports rose by 0.6 TWh. The decrease in net exports over the

[146] Although the constrained schedules provide a better picture of actual flows of power on the interties, they do not impact ICPs or the Ontario uniform price.

Winter 2017/18 Period was primarily driven by a large decrease in exports to Michigan and the large increase in imports from Québec, compared to the Winter 2016/17 Period.

Figure A-25: Exports by Intertie

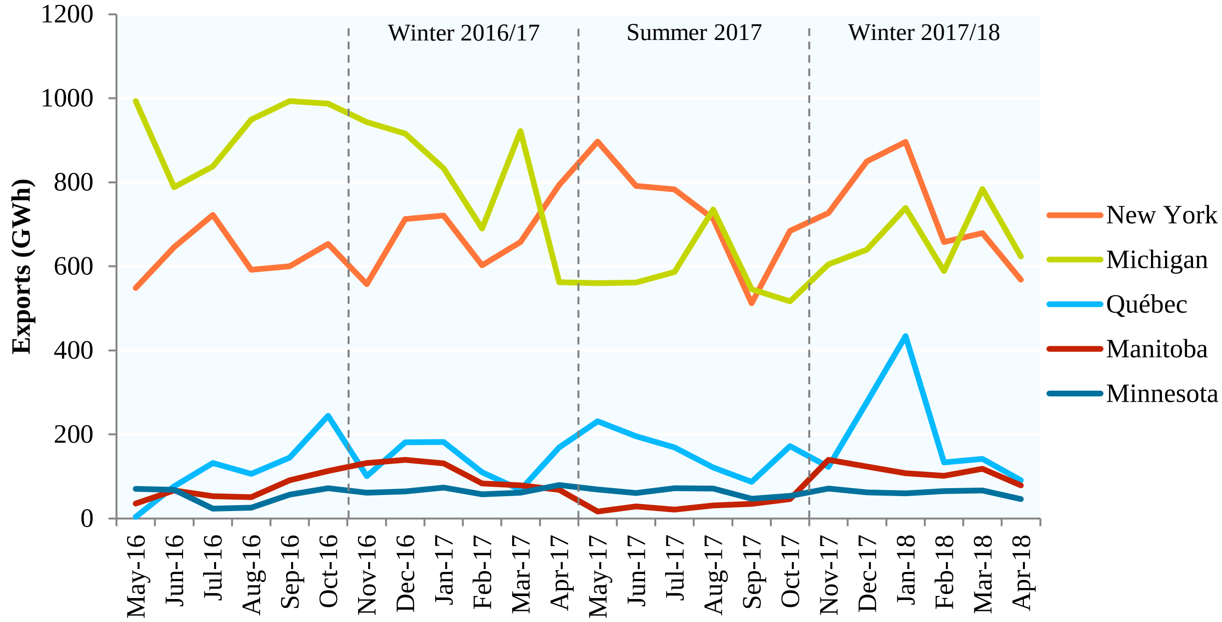


Figure A-25 presents the breakdown of exports from May 2016 to April 2018 to and from each of Ontario's five neighboring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. The average monthly export quantities over the Winter 2017/18 and Summer 2017 Periods are given for each intertie in Table A-7.

Exports to Québec during the Winter 2017/18 Period were significantly higher than in the Winter 2016/17 Period, and modestly higher than the Summer 2017 Period. This result was largely driven by exports in January 2018, which were more than 150 GWh higher than any other month in the last three reporting periods. Exports to Manitoba and New York increased slightly relative to the Winter 2016/17 Period, whereas Minnesota exports decreased slightly. Michigan exports decreased more substantially in the Winter 2017/18 Period compared to the Winter 2016/17 Period, falling by 18%. This decrease can be attributed to an increase in the duration and number of the scheduled outages of equipment in the West Zone in the Winter 2017/18 Period that reduce the transmission limit of the Ontario-Michigan intertie.

Figure A-26: Imports by Intertie

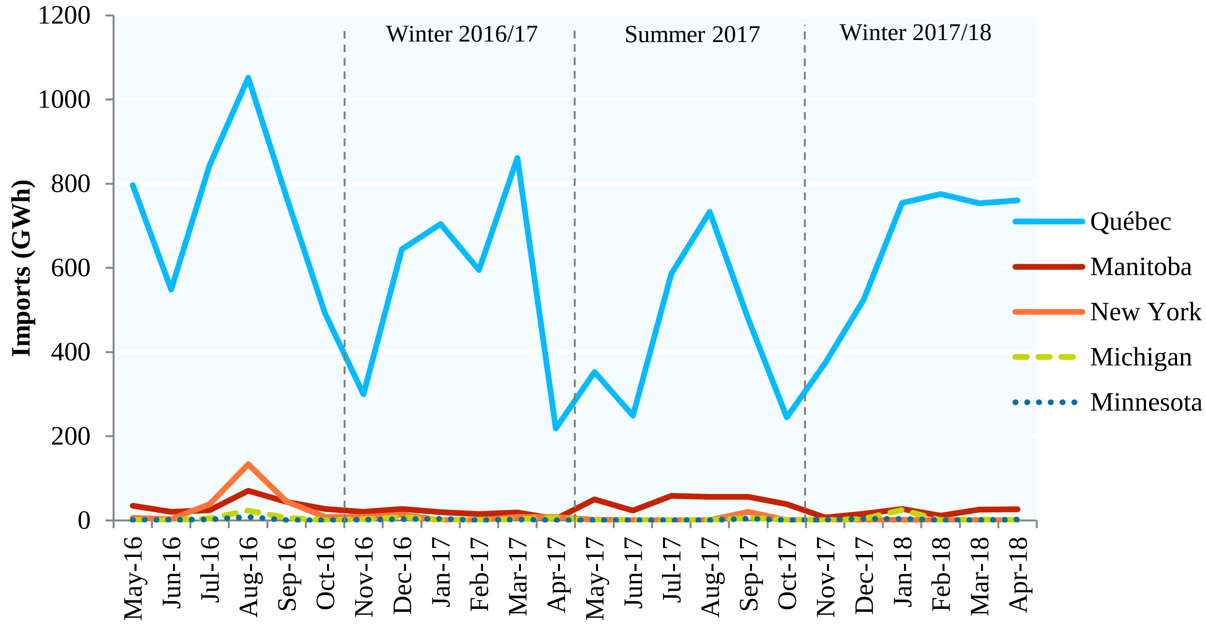


Figure A-26 presents the breakdown of imports from May 2016 to April 2018 to and from each of Ontario's five neighboring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. The average monthly import quantities over the Winter 2017/18 and Summer 2017 Periods are given for each intertie in Table A-8.

Imports from Québec increased by 19% on average compared to the Winter 2016/17 Period, and remained at that level between January and April of 2018. The overall increase in imports from Québec was likely caused by the increase in demand for energy in the Winter 2017/18 Period compared to the Winter 2016/17 Period. In previous reporting periods, Ontario imported more energy from Québec between July and September and between January and March, likely due to hot and cold weather conditions increasing the use of air conditioning and electric heating, respectively. As April was both particularly cold in Ontario and had a higher HOEP on average compared to previous years, the amount of energy Ontario imported from Québec remained high, resulting in a trend of constant imports as mentioned above. Average imports from Michigan, Manitoba, Minnesota and New York all remained under 20 GWh per month throughout the Winter 2017/18 Period, as they did in the Winter 2016/17 Period.

Table A-7: Average Monthly Export Failures by Intertie and Cause

Intertie	Average Monthly Exports (GWh)		Average Monthly Export Failure and Curtailment (GWh)				Export Failure and Curtailment Rate			
			ISO Curtailment		MP Failure		ISO Curtailment		MP Failure	
	Winter 2017/18	Summer 2017	Winter 2017/18	Summer 2017	Winter 2017/18	Summer 2017	Winter 2017/18	Summer 2017	Winter 2017/18	Summer 2017
New York	708	701	2.0	2.6	8.0	11.6	0.3%	0.4%	1.1%	1.7%
Michigan	562	456	3.2	1.8	5.2	6.3	0.6%	0.4%	1.0%	1.4%
Manitoba	107	43	1.6	3.0	12.1	15.7	1.5%	7.1%	11.2%	36.4%
Minnesota	33	50	0.6	1.2	0.7	0.7	1.7%	2.5%	2.0%	1.4%
Québec	201	176	8.3	2.5	3.3	2.0	4.2%	1.5%	1.7%	1.1%

Table A-7 reports average monthly export curtailments and failures over the Winter 2017/18 Period and the Summer 2017 Period by intertie and cause. The failure and curtailment rates are expressed as a percentage of total (constrained) exports over each intertie, excluding linked wheel transactions.[147] Curtailment (ISO Curtailment) refers to an action taken by a system operator, typically for reliability or security reasons. Failure (MP Failure) refers to a transaction that fails for reasons within the control of the Market Participant (MP) such as a failure to obtain transmission service.

Failed or curtailed exports reduce demand between PD-1 and real-time. The MP percentage failure rate of exports on the Manitoba intertie, which has consistently been above that of the other interties in previous periods, fell significantly, due to an increase in volume of total exports relative to failed ones. This increase is at least partly seasonal: exports to Manitoba have been higher in the winter in past years compared to the summer. The Québec intertie experienced an increase in ISO-curtailed exports in the Winter 2017/18 Period to 4.2% when compared to the Summer 2017 Period, but was lower than the curtailment rate of 7.7% seen in the Winter 2016/17 Period. This increase is also seasonal – on average, Québec faces a

[147] A linked wheel transaction is one in which an import and an export are explicitly linked together from a scheduling perspective, with the intention of moving power through Ontario.

greater amount of reliability-related curtailments during the winter compared to the summer, as seen in previous winter reporting periods.

Table A-8: Average Monthly Import Failures by Intertie and Cause

Intertie	Average Monthly Imports (GWh)		Average Monthly Import Failure and Curtailment (GWh)				Import Failure and Curtailment Rate			
			ISO Curtailment		MP Failure		ISO Curtailment		MP Failure	
	Winter 2017/18	Summer 2017	Winter 2017/18	Summer 2017	Winter 2017/18	Summer 2017	Winter 2017/18	Summer 2017	Winter 2017/18	Summer 2017
New York	8	5	0.1	0.5	0.2	0.1	0.9%	8.9%	2.2%	1.4%
Michigan	9	3	0.5	0.5	3.0	0.9	4.8%	15.9%	31.9%	30.6%
Manitoba	69	64	1.2	12.0	0.2	0.3	1.8%	19.0%	0.3%	0.4%
Minnesota	23	5	0.6	0.6	1.7	0.7	2.5%	11.4%	7.4%	13.7%
Québec	514	336	5.0	6.3	0.1	0.2	1.0%	1.9%	0.0%	0.1%

Table A-8 reports average monthly import failures and curtailments the Winter 2017/18 Period and the Summer 2017 Period by intertie and cause. The MP Failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel transactions.

Failed or curtailed imports reduce supply between the PD-1 and real-time. This change in supply can lead to a sub-optimal level of intertie transactions and may contribute to increases in price. The IESO may dispatch up domestic generation or curtail exports to compensate for MP Failures and ISO Curtailments. The percentage rate of ISO Curtailments for imports decreased in the Winter 2017/18 Period compared to the Summer 2017 Period for all interties, due to a decrease in import volume, an increase in the average monthly volume of curtailments, or both. In particular, ISO-related curtailments on the Manitoba intertie fell sharply, due to a decrease in the total GWh of imports curtailed. The number of MP Failure rates remained broadly stable – however, the Minnesota intertie's MP Failure rate decreased due to a large increase in total imports compared to the Summer 2017 Period.